SWIFT ENERGY CO
Form 10-K
March 01, 2007

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, 2006

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

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 x No

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 No x

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 x No

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. [ ]

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 x Accelerated filer ____ Non-accelerated filer ____

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

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 2006 was approximately $1,233,453,469.

The number of shares of common stock outstanding as of January 31, 2007 was 29,803,934.

Documents Incorporated by Reference

Document	Incorporated as to
Proxy Statement for the Annual Meeting of Shareholders to be held May 8, 2007	Part II, Item 5 Part III, Items 10, 11, 12, 13 and 14

Form 10-K
Swift Energy Company and Subsidiaries

10-K Part and Item No.

(1) Incorporated by reference from Proxy Statement for the Annual Meeting. of Shareholders to be held May 8, 2007.

PART I

Item 1. Business

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 2006, we had estimated proved reserves of 816.8 Bcfe with a PV-10 Value of $2.7 billion (PV-10 is a non-GAAP measure, see the section titled "Oil and Natural Gas Reserves" in our Property section for a reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure). Our proved reserves at year-end 2006 were comprised of approximately 50% crude oil, 40% natural gas, and 10% NGLs; and 44% of our total proved reserves were proved developed. Our proved reserves are concentrated 64% in Louisiana, 22% in Texas, 13% 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
  - Bay de Chene Area
  - Bayou Penchant Area
  - Bayou Sale Area
  - Cote Blanche Island Area
  - High Island Area
  - Horseshoe Bayou Area
  - Jeanerette Area
  - Lake Washington Area

- South Texas Region
  - AWP Olmos 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

We have grown our proved reserves from 645.8 Bcfe to 816.8 Bcfe over the five-year period ended December 31, 2006. Over the same period, our annual production has grown from 44.8 Bcfe to 70.2 Bcfe and our annual net cash provided by operations has increased from $139.9 million to $424.9 million. Our

growth in reserves and production over this five-year period has resulted primarily from drilling activities and acquisitions in our four core regions. More recently, we increased our production by 18% during 2006 as compared to our hurricane affected 2005 production. During 2006, our total proved reserves increased by 7%, primarily due to acquisitions of properties in our South Louisiana region. 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 also focus on 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, 2006, we replaced 159% of our production at an average cost of $2.76 per Mcfe. More recently, we replaced 178% of our 2006 production at an average cost of $4.29 per Mcfe. For 2007, we are targeting total production to increase 7% to 10% and proved reserves to increase 4% to 6% over 2006 levels.

Our 2007 capital expenditures are currently budgeted at $350 million to $400 million, net of minor non-core dispositions and excluding any property acquisitions.

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 listing of 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, adverse weather conditions, 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 the oil and gas. Development costs thus include well drilling 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 leverage our drilling unit and workforce synergies while minimizing the continued escalation of drilling and completion costs. Our average lease operating costs, excluding taxes, were $0.89, $0.79, and $0.71 per Mcfe in 2006, 2005, and 2004, respectively. 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. 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 operational control of 94% of our proved oil and natural gas reserves base as of December 31, 2006. 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 18,700 BOE for the quarter ended December 31, 2006. We have also increased our proved reserves in the area from 7.7 million BOE, or 46.2 Bcfe, to approximately 40.3 million BOE or 241.9 Bcfe, as of December 31, 2006. Additionally, on our original 100,000 acre New Zealand permit, only two wells had been drilled at the time that we acquired our interest in 1999 and since that time we have drilled 50 wells in New Zealand. 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 began 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.

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, 2006, our debt to capitalization was approximately 32%, while our debt to proved reserves ratio was $0.47 per Mcfe, and our debt to PV-10 ratio was 14%. We plan to maintain a capital structure that provides 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 61 oil and gas professionals, including geophysicists, petrophysicists, geologists, petroleum engineers, and production and reservoir engineers, who have an average of approximately 24 years of experience in their technical fields and have been employed by us for an average of over five 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 increasingly use seismic technology to enhance the results of our drilling and production efforts, including two and three-dimensional seismic acquisition, pre-stack image enhancement reprocessing, amplitude versus offset datasets, coherency cubes, and detailed field reservoir depletion planning. In 2004, we completed our 3-D seismic survey covering our Lake Washington area. In 2006 we utilized this seismic data to drill all of our exploratory and development wells. In 2005, we began a seismic program that encompasses 77 square miles in our Cote Blanche Island area, which was completed in 2006 and analysis of this data will continue into 2007. We now have seismic data covering 4,000 square miles in South Louisiana that has been merged into two data sets, inclusive of data covering five newly acquired fields that will form the base dataset for our regional exploration and development program. This data will be analyzed over the next several years feeding our acquisition and organic growth led strategies. In New Zealand, we also acquired 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 also employ measurement-while-drilling techniques extensively in our South Louisiana region, 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.

Item 2. Properties

Operating Areas

The following table sets forth information regarding our 2006 year-end proved reserves of 816.8 Bcfe and production of 70.2 Bcfe by field:

Area	% of Year-End 2006 Proved Reserves	% of 2006 Production
New Zealand.................	13%	19%
South Louisiana.............	53%	61%
South Texas.................	18%	12%
Toledo Bend.................	14%	6%
% of Total...........	98%	98%

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. 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, and adding five fields in 2006: Bayou Sale, Bayou Penchant, High Island, Horseshoe Bayou, and Jeanerette.

South Louisiana

Lake Washington Area. As of December 31, 2006, we owned drilling and production rights in 21,690 net acres in the Lake Washington area located in Plaquemines Parish in South Louisiana. Approximately 93% of our proved reserves of 40.3 million BOE in this area at December 31, 2006, were oil and NGLs. To date, we have primarily produced from multiple Miocene sands ranging in depth from greater than 2,000 feet to 13,000 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 146 producing wells is gathered to three platforms located in water depths from two to 12 feet, with drilling and workover operations performed with rigs on barges.

In 2006, we drilled 21 development wells, of which 18 wells were completed. At year-end 2006, we had 109 proved undeveloped locations in this field. Our planned 2007 capital expenditures in this area will focus on drilling from 24 to 26 wells, along with the construction of a facility on the west side of the field 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, 2006, we owned drilling and production rights in 16,138 net acres in the Bay de Chene field and 7,030 net acres in the Cote Blanche Island field, along with options covering another 16,650 acres in the Cote Blanche Island field. At year-end 2006, we had five proved undeveloped locations in the Bay de Chene field and 26 in the Cote Blanche Island field. We drilled six development wells in Bay de Chene in 2006, of which three were completed, and we drilled three successful development wells in Cote Blanche Island. During 2007, we plan to drill six to eight wells in Bay de Chene and up to two wells in Cote Blanche Island, along with processing the 3-D seismic data that was shot in Cote Blanche Island in 2006.

Newly Acquired South Louisiana Areas. In October 2006, we acquired interests in five fields located in five primarily onshore South Louisiana fields: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), High Island Field in Cameron Parish and Bayou Penchant Field in Terrebonne Parish. Bayou Sale and Horseshoe Bayou fields are adjacent to each other and located 13 miles southeast of our Cote Blanche Island field. Production in these fields is from formations at depths ranging from 10,000 to 14,000 feet. The Bayou Penchant field was discovered in the 1930s and produces from a number of Middle Miocene sands at depths of 7,000 to 10,000 feet. Bayou Penchant is located approximately 44 miles southeast of Cote Blanche Island and is a non-operated field with Swift holding a 50% working interest. The High Island field is located 65 miles west of Cote Blanche Island and was discovered in 1983. The Jeanerette field is positioned on the flank of a large salt dome and approximately 12 miles north of Cote Blanche Island. Jeanerette Field produces from the Planulina sands in the 10,000 feet to 15,000 feet depth range. We plan to initiate an exploration and development program in 2007 to drill proved undeveloped and probable locations, recomplete several wells, enhance facilities and improve per unit operating costs in these five fields.

South Texas

AWP Olmos Area. As of December 31, 2006, we owned drilling and production rights in 29,278 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 70% natural gas. At year-end 2006, we owned interests in and operated 540 wells in this area producing oil and 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 these operated wells.

In 2006, we completed 14 development wells in this area, performed 26 fracture enhancements, but were unsuccessful on five very shallow exploration wells which cost $0.5 million in the aggregate. At year-end 2006, we had 110 proved undeveloped locations. Our planned 2007 capital expenditures will focus on drilling 10 to 12 wells in this area.

Toledo Bend

Brookeland Area. As of December 31, 2006, we owned drilling and production rights in 79,593 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 2006, we drilled one development well, which was successful. At year-end 2006, we had ten proved undeveloped locations. Our planned 2007 capital expenditures in the Brookeland area include drilling one to two development wells.

Masters Creek Area. As of December 31, 2006, we owned drilling and production rights in 41,988 net acres and 91,594 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 69% oil and NGLs. At year-end 2006, we had nine proved undeveloped locations. We do not plan on drilling any wells in this area in 2007.

South Bearhead Creek Area. In November and December 2005, and then in December 2006, 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 14,100 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.

In 2006, we drilled three development wells in the area, all of which were successful. As of December 31, 2006, we owned drilling and production rights in 6,258 net acres in the South Bearhead Creek area. At year-end 2006, we had 19 proved undeveloped locations in this field. Our 2007 plans for this area include two to four development wells and several recompletions.

Dispositions. In April 2006, we sold our minority interest in the natural gas processing plant and related infrastructure that serves the Brookeland and the Masters Creek areas within our Toledo Bend region. In December 2006, we sold our interest in wells in the Garcia Ranch area within the South Texas region.

New Zealand Regional Focus Areas

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, 2006, our exploration and production permits, all of which we operate, total 314,360 acres (182,381 net acres). Our 2007 planned activity in New Zealand includes conducting a major 3-D seismic survey and possibly drilling two development wells. 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.

Rimu/Kauri Area. Since 2002, we have held a 100% working interest in petroleum mining permit 38151 covering approximately 4,552 acres in the Rimu area for a primary term of 30 years. We were awarded a 30-year primary term mining permit (PMP 38155) covering approximately 8,708 acres in the Kauri area in April 2005. During 2006, we completed two out of three development wells in the Kauri area and were unsuccessful with one exploratory well. One of the development wells successfully targeted the Kauri and Tariki sands, and the other was completed in the Manutahi sand. 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 2006, we completed the Waihapa H-1 development well in the Tikorangi sand in this area and were unsuccessful with two exploratory wells, the Trapper and Goss. The TAWN assets are located approximately 17 miles north of the Rimu/Kauri area.

Diversity Areas. A 152 square kilometer (59 square miles) marine 3-D seismic survey was recorded in production exploration permit 38495 over the Kaheru prospect, which is situated on the southern, offshore extension of the productive Rimu-Kauri structural trend, as a precursor to the possible drilling of an exploratory well on this prospect in 2008. We own 50% of this prospect.

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. The Kowhai A-1 exploratory well was drilled in this area in the second half of 2006 but was unsuccessful.

Summary of New Zealand Government Licenses and Permits

Our acreage in New Zealand is licensed from the New Zealand government under production exploration permits (PEP), production mining licenses (PML), and production mining permits (PMP). These licenses and permits as of December 31, 2006 are summarized in the following table:

Permit	Date of Initial Interest Acquired	Swift's Interest
PEP 38495	2005	50%
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, 2006, 2005, and 2004. 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 were 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 proved and are not reflected in the following tables. Our hedges at year-end 2006 consisted of natural gas price floors with strike prices higher than the period-end price but did not materially affect prices used in these calculations. The weighted averages of such year-end 2006 prices domestically were $5.84 per Mcf of natural gas, $60.07 per barrel of oil, and $31.54 per barrel of NGL, compared to $10.36, $60.00, and $33.28 at year-end 2005 and $5.87, $42.21, and $26.49 at year-end 2004, respectively. The weighted averages of such year-end 2006 prices for New Zealand were $3.59 per Mcf of natural gas, $63.51 per barrel of oil, and $26.84 per barrel of NGL, compared to $3.79, $60.98, and $19.20 in 2005 and $3.07, $33.60, and $20.48 in 2004, respectively. The weighted averages of such year-end 2006 prices for all our reserves, both domestically and in New Zealand, were $5.46 per Mcf of natural gas, $60.41 per barrel of oil, and $30.93 per barrel of NGL, compared to $8.94, $60.12, and $31.40 in 2005 and $5.16, $41.07, and $25.48 in 2004, 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, 2006, 2005, and 2004. 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
	Total
Estimated Proved Oil and Natural Gas Reserves	
Natural gas reserves (MMcf):	
Proved developed	151,276
Proved undeveloped	172,855
Total	324,131
Oil reserves (MBbl):	
Proved developed	34,956

Proved undeveloped	47,163
Total	82,119
Total Estimated Reserves (Bcfe)	817
Estimated Discounted Present Value of Proved Reserves (In millions)	
Proved developed	$ 1,382 $
Proved undeveloped	1,326
PV-10 Value	$ 2,708 $

	As of
	Total
Estimated Proved Oil and Natural Gas Reserves	
Natural gas reserves (MMcf):	
Proved developed	152,001
Proved undeveloped	135,472
Total	287,473
Oil reserves (MBbl):	
Proved developed	37,990
Proved undeveloped	41,063
Total	79,053
Total Estimated Reserves (Bcfe)	762
Estimated Discounted Present Value of Proved Reserves (In millions)	
Proved developed	$ 1,721 $
Proved undeveloped	1,450
PV-10 Value	$ 3,171 $

	As of
	Total
Estimated Proved Oil and Natural Gas Reserves	
Natural gas reserves (MMcf):	
Proved developed	193,311
Proved undeveloped	124,935
Total	318,246

Oil reserves (MBbl):		
Proved developed	42,038	
Proved undeveloped	38,229	
Total	80,267	
Total Estimated Reserves (Bcfe)	800	
Estimated Discounted Present Value of Proved Reserves (In millions)		
Proved developed	$ 1,182	$
Proved undeveloped	839	
PV-10 Value	$ 2,021	$

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.

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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:

	A
	Total
(In millions)	
PV-10 Value	$ 2,

Future income taxes (discounted at 10%)...	(
Asset retirement obligations (discounted at 10%)......................................	
Standardized Measure of Discounted Future Net Cash Flows relating to oil and gas reserves	$ 1,

	Total
(In millions)	
PV-10 Value	$ 3,
Future income taxes (discounted at 10%)...	(
Asset retirement obligations (discounted at 10%)......................................	
Standardized Measure of Discounted Future Net Cash Flows relating to oil and gas reserves	$ 2,

	Total
(In millions)	
PV-10 Value	$ 2,
Future income taxes (discounted at 10%)...	(
Asset retirement obligations (discounted at 10%)......................................	
Standardized Measure of Discounted Future Net Cash Flows relating to oil and gas reserves	$ 1,

Proved Undeveloped Reserves

The following table sets forth the aging and PV-10 value of our proved undeveloped reserves as of December 31, 2006:

Year Added	Volume (Bcfe)	% of PUD Volumes	PV-10 Value (in millions)	% o PV-10
2006	111.9	25%	$ 315.9	
2005	110.6	24%	406.5	
2004	58.4	13%	189.9	
2003	51.4	11%	171.4	
2002	40.3	9%	91.6	
Prior to 2002	83.2	18%	151.2	
Total	455.8	100%	$ 1,326.5	

Sensitivity of Reserves to Pricing

As of December 31, 2006, a 5% increase in crude oil and NGL pricing would increase our total estimated proved reserves of 816.8 Bcfe by approximately 0.6 Bcfe, and increase the total PV-10 Value of $2.7 billion by approximately $139 million. Similarly, a 5% decrease in crude oil and NGL pricing would decrease our total estimated proved reserves by approximately 0.6 Bcfe and decrease the total PV-10 Value by approximately $138 million.

As of December 31, 2006 a 5% increase in natural gas pricing (exclusive of fixed contract volumes) would increase our total estimated proved reserves by approximately 0.7 Bcfe and increase the total PV-10 Value by approximately $42 million. Similarly, a 5% decrease in natural gas pricing (exclusive of fixed contract volumes) would decrease our total estimated proved reserves by approximately 0.6 Bcfe and decrease the total PV-10 Value by approximately $42 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, 2006:			
Gross................................	423	662	1,085
Net..................................	353.4	562.4	915.8
December 31, 2005:			
Gross................................	402	565	967
Net..................................	324.8	497.5	822.3
December 31, 2004:			
Gross................................	358	574	932
Net..................................	308.8	525.9	834.7

(1) Excludes 51 service wells in 2006, 49 service wells in 2005, and 40 service wells in 2004.

Oil and Gas Acreage

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2006:

	Developed(1)		Undeveloped
	Gross	Net	Gross
Alabama....................................	9,045	2,588	124
Alaska.....................................	---	---	45,301
Louisiana..................................	126,472	106,133	48,376

Texas....................................	129,997	90,165	18,271	
SWyoming.................................	640	151	35,771	
All other states.........................	320	266	400	
Offshore Louisiana.......................	4,609	277	5,000	
Total Domestic...........................	271,083	199,580	153,243	
New Zealand..............................	9,960	9,912	304,400	
Total....................................	281,043	209,492	457,643	

(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 68,689 undeveloped fee mineral acres for a total of 95,034 fee mineral acres.

Drilling Activities

The following table sets forth the results of our drilling activities during the three years ended December 31, 2006:

for a total of 95,034 fee mineral areas

Year	Type of Well	Gross Wells Total	Gross Wells Producing	Gross Wells Dry	Net Wells Total	Net Wells Producing
2006	Exploratory -- Domestic	6	--	6	5.5	--
	Development -- Domestic	49	42	7	47.6	40.6
	Exploratory -- New Zealand	4	--	4	4.0	--
	Development -- New Zealand	4	3	1	4.0	3.0
2005	Exploratory -- Domestic	9	5	4	9.0	5.0
	Development -- Domestic	45	37	8	44.3	36.3
	Exploratory -- New Zealand	5	1	4	3.7	1.0
	Development -- New Zealand	5	2	3	5.0	2.0
2004	Exploratory -- Domestic	10	4	6	7.5	2.3
	Development -- Domestic	44	37	7	41.7	35.0
	Exploratory -- New Zealand	1	--	1	1.0	--
	Development -- New Zealand	11	10	1	11.0	10.0

Operations

We generally seek to be the operator of 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 2006 totaled $8.8 million and ranged from $529 to $2,345 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. In 2005 and 2006, several companies accounted for 10% or more of our total revenues. Shell Oil Company and its affiliates, both domestically and in New Zealand, accounted for approximately 30% and 42% of our total oil and gas sales in 2006 and 2005, respectively. In 2006, Chevron and its domestic affiliates accounted for 32% of our total oil and gas sales. 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.

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.

In the Toledo Bend area, our oil production from the Brookeland, Masters Creek and South Bearhead Creek areas is sold to various purchasers at prevailing market prices. Our natural gas production from the Brookeland and Masters Creek areas is processed under long term gas processing contracts with Eagle Rock Operating, LLC. The processed liquids and residue gas production are sold in the spot market at prevailing prices. South Bearhead Creek gas production is sold into the interstate market on Trunkline Gas Company's pipeline at prevailing market prices.

Our oil production from the Bay de Chene and Cote Blanche Island fields is transported on barges for sales to various purchasers at prevailing market prices. Gas production from both fields is sold into intrastate pipelines with prices tied to monthly and daily gas price indices.

In the newly acquired fields of Bayou Sale, Horseshoe Bayou, High Island and Jeanerette in south Louisiana, we market our own production and sell the oil production to various purchasers at prevailing market prices. Bayou Sale and Horseshoe Bayou oil production is delivered into Plains All-American pipeline. Oil production from High Island and Jeanerette fields is transported to market by truck. Gas production for each of these fields is sold into one or more interstate pipelines at prevailing market prices.

Through 2006, our oil production in New Zealand was sold to BP with prices tied to the Asia Petroleum Price Index (APPI) Tapis posting.

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 2006 and covers approximately 7.2 Bcfe per year for a three-year period. During 2006, 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, 2006:

	Year Ended December 31,		
	2006	2005	2004
Net Sales Volume:			
Oil (MBbls)(1)	7,190	5,159	4,722
Natural Gas Liquids (MBbls)(2)	713	838	1,040
Natural gas (MMcf)(3)	22,788	23,609	23,742
Total (MMcfe)	70,205	59,590	58,319
Average Sales Price:			
Oil (Per Bbl)(1)	$ 64.47	$ 53.63	$ 40.24
Natural Gas Liquids (Per Bbl)(2)	$ 32.15	$ 28.04	$ 22.52
Natural gas (Per Mcf)(3)	$ 5.05	$ 5.23	$ 4.12
Average Production Cost (Per Mcfe)	$ 1.82	$ 1.50	$ 1.23

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(1) Oil production for 2006, 2005, and 2004 includes New Zealand production of 468,813 barrels at an average price per barrel of $67.06, 449,994 barrels at an average price per barrel of $55.57, and 452,753 barrels at an average price per barrel of $42.15, respectively.

(2) Natural gas liquids production for 2006, 2005 and 2004 includes New Zealand production of 252,666 barrels at an average price of $20.22 per barrel, 329,377 barrels with an average price of $18.84 per barrel, and 350,303 barrels with an average price of $17.96 per barrel.

(3) Natural gas production for 2006, 2005 and 2004 includes New Zealand production of 9,184,359 Mcf with an average price of $2.99 per Mcf, 11,869,757 Mcf with an average price of $3.09 per Mcf, and 11,441,954 Mcf with an average price of $2.38 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 business interruption 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, 2006, we had price floors in place through the March 2007 contract month for natural gas; these cover a portion of our domestic natural gas production for February 2007 to March 2007. The natural gas price floors cover notional volumes of 800,000 MMBtu, with a weighted average floor price of $7.00 per MMBtu. Our natural gas price floors in place at December 31, 2006 are expected to cover approximately 25% to 30% of our domestic natural gas production from February 2007 to March 2007.

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 and acquisition.

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 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 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, 2006, we employed 345 persons. Of these employees, 73 were in New Zealand, including two 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, 2006, we occupied approximately 124,000 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 $240,000 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 $20,000 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.

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, 2006, our total debt comprised approximately 32% 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 level of indebtedness could negatively affect us in several ways:

o require us to dedicate a substantial portion of our cash flow to the payment of interest;

o subject us to a higher financial risk in an economic downturn due to substantial debt service costs;

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

o 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 poved 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, 2006, approximately 56% 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 increse 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:

o hurricanes or tropical storms;

o 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;

o abnormally pressured formations;

o mechanical difficulties, such as stuck oil field drilling and service. tools and casing collapse;

o fires and explosions;

o personal injuries and death; and

o 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 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 as 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.

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 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 2006 consisted of natural gas price floors with strike prices higher than the period end prices. Our hedging transactions have also historically 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.

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 egulations 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.

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. New Zealand income taxes are also computed 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.

Item 1B. Unresolved Staff Comments

None.

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.

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).

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.

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 2006 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, 2005 and 2006

Our common stock is traded on the New York Stock Exchange under the symbol "SFY." The high and low quarterly closing sales prices for the common stock for 2005 and 2006 were as follows:

	2005				2006			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$24.77	$26.22	$37.31	$39.82	$35.48	$35.61	$40.06	$39.10
High	$30.64	$36.75	$48.86	$50.01	$49.50	$45.22	$48.00	$51.84

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 252 stockholders of record as of December 31, 2006.

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 the Proxy Statement for our annual meeting to be held May 8, 2007 ("Proxy Statement"), which Proxy Statement is to be filed within 120 days after Registrant's fiscal year end of December 31, 2006, and which information is incorporated herein by reference.

Share Performance Graph

The following Share Performance Graph shall not be deemed to be "soliciting material" or to be "filed" with the Securities and Exchange Commission, nor shall such information be incorporated by reference into any future filings under the Securities Act of 1933 or Securities Exchange Act of 1934, each as amended, except to the extent that the Company specifically incorporates it by reference into such filing.

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Date*	Transaction Type	Closing Price**	Beginning No. Of Shares***	Dividend per Share	Dividend Paid	Shares Reinvested	Ending Shares
31-Dec-01	Begin	20.200	4.95				4.950
31-Dec-02	Year End	9.670	4.95				4.950
31-Dec-03	Year End	16.850	4.95				4.950

31-Dec-04	Year End	28.940	4.95	4.950
31-Dec-05	Year End	45.070	4.95	4.950
31-Dec-06	End	44.810	4.95	4.950

* Specified ending dates or ex-dividends dates.
** All Closing Prices and Dividends are adjusted for stock splits and stock dividends.
***'Begin Shares' based on $100 investment.

[GRAPHIC OMITTED]

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Item 6. Selected Financial Data

	2006	2005	2004	
Total Revenues	$615,441,230	$423,226,489	$310,276,774	$
Income (Loss) Before Income Taxes and Change in Accounting Principle (1)	$262,286,165	$178,439,551	$101,440,242	
Net Income (Loss)	$161,565,340	$115,778,456	$68,450,917	
Net Cash Provided by Operating Activities	$424,921,046	$285,333,484	$182,582,887	$
Per Share Data				
Weighted Average Shares Outstanding(1)	29,265,366	28,496,275	27,822,413	
Earnings (Loss) per Share--Basic(1)	$5.52	$4.06	$2.46	
Earnings (Loss) per Share--Diluted(1)	$5.38	$3.95	$2.41	
Shares Outstanding at Year-End	29,742,918	29,009,530	28,089,764	
Book Value per Share at Year-End	$26.83	$20.94	$16.88	
Market Price(1)				
High	$51.84	$50.01	$30.34	
Low	$35.48	$24.77	$15.90	
Year-End Close	$44.81	$45.07	$28.94	
Effect on Net Income and Earnings Per Share From Changes in Accounting Principles (2)				
Cumulative Effect of Change in Accounting Principle (Net of Taxes)	---	---	---	
Effect per Share--Basic	---	---	---	
Effect per Share--Diluted	---	---	---	
Assets				
Current Assets	$92,573,041	$115,055,135	$54,385,996	
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	$1,483,312,165	$1,079,033,739	$923,438,160	$
Total Assets	$1,585,681,758	$1,204,412,622	$990,573,147	$

Liabilities				
Current Liabilities	$145,975,288	$98,421,014	$68,618,291	
Long-Term Debt	$381,400,000	$350,000,000	$357,500,000	$
Total Liabilities	$787,764,786	$597,094,455	$516,401,007	$
Stockholders' Equity	$797,916,972	$607,318,167	$474,172,140	$
Number of Employees	345	311	272	
Producing Wells				
Swift Operated	973	898	835	
Outside Operated	112	69	97	
Total Producing Wells	1,085	967	932	
Wells Drilled (Gross)	63	64	66	
Proved Reserves				
Natural Gas (Mcf)	324,131,417	287,473,150	318,246,294	
Oil, NGL, & Condensate (barrels)	82,119,084	79,053,056	80,267,208	
Total Proved Reserves (Mcf equivalent)	816,845,916	761,791,482	799,849,539	
Production (Mcf equivalent)(3)	70,204,544	59,589,526	58,318,502	
Average Sales Price				
Natural Gas (per Mcf)	$5.05	$5.23	$4.12	
Natural Gas Liquids (per barrel)(4)	$32.15	$28.04	$22.52	
Oil (per barrel)(4)	$64.47	$53.63	$40.24	
Mcf Equivalent	$8.57	$7.11	$5.34	

(1)Amounts have been retroactively restated in all periods presented to give recognition to: (a) the adoption in 1998 of Statement of Financial Accounting Standards No. 128, "Earnings per Share," and (b) 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.

(3)Natural gas production from 1996 to 2000 includes volumes under a production payment agreement ranging from 1.2 Bcfe in 1996 to 0.4 Bcfe in 2000.

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

2001	2000	1999	1998	1997	1996
$183,807,490	$191,624,946	$110,671,007	$82,469,221	$74,712,180	$56,298,026

($34,192,333)	92,449,488	$29,736,151	($73,391,581)	$33,129,606	$28,785,783
($22,347,765)	$59,184,008	$19,286,574	($48,225,204)	$22,310,189	$19,025,450
$139,884,255	$128,197,227	$73,603,426	$54,249,017	$55,255,965	$37,102,578
24,732,099	21,244,684	18,050,106	16,436,972	16,492,856	15,000,901
($0.90)	$2.79	$1.07	($2.93)	$1.35	$1.27
($0.90)	$2.51	$1.07	($2.93)	$1.26	$1.25
24,795,564	24,608,344	20,823,729	16,291,242	16,459,156	15,176,417
$12.61	$13.50	$8.18	$6.71	$9.69	$9.41
$37.70	$43.50	$13.31	$21.00	$34.20	$28.86
$16.66	$9.75	$5.69	$6.94	$16.93	$9.89
$20.20	$37.63	$11.50	$7.38	$21.06	$27.16
($392,868)	---	---	---	---	---
($0.01)	---	---	---	---	---
($0.01)	---	---	---	---	---
$36,752,980	$41,872,879	$50,605,488	$35,246,431	$29,981,786	$101,619,478
$628,304,060	$524,052,828	$392,986,589	$356,711,711	$301,312,847	$200,010,375
$671,684,833	$572,387,001	$454,299,414	$403,645,267	$339,115,390	$310,375,264
$73,245,335	$64,324,771	$34,070,085	$31,415,054	$28,517,664	$32,915,616
$258,197,128	$134,729,485	$239,068,423	$261,200,000	$122,915,000	$115,000,000
$359,032,113	$240,232,846	$283,895,297	$294,282,628	$179,714,470	$167,613,654
$312,652,720	$332,154,155	$170,404,117	$109,362,639	$159,400,920	$142,761,610
209	181	173	203	194	191
854	817	769	836	650	842
381	711	788	917	917	986
1,235	1,528	1,557	1,753	1,567	1,828
53	70	27	75	182	153
324,912,125	418,613,976	329,959,750	352,400,835	314,305,669	225,758,201
53,482,636	35,133,596	20,806,263	13,957,925	7,858,918	5,484,309
645,807,939	629,415,552	454,797,327	436,148,385	361,459,177	258,664,055
44,791,202	42,356,705	42,874,303	39,030,030	25,393,744	19,437,114
$4.23	$4.24	$2.40	$2.08	$2.68	$2.57
---	---	---	---	---	---
$22.64	$29.35	$16.75	$11.86	$17.59	$19.82

$4.05	$4.47	$2.54	$2.05	$2.72	$2.71

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, 2006, 2005, and 2004 included with this report. The following information contains forward-looking statement;, see "Forward-Looking Statements" on page 45 of this report.

Overview

Swift Energy had record net income, cash flow, and production for 2006. Net income increased 40% to $161.6 million and cash flow from operations increased 49% to $425 million, in each case compared to 2005 amounts. Production increased 18% to 70.2 Bcfe over hurricane affected production a year earlier, principally attributable to our continued success in Lake Washington, with our 2006 production increase matching in one year our cumulative production increase over the prior three years. We ended 2006 with total proved reserves of 817 Bcfe, an increase of 7% over year-end 2005 reserves. We also had record revenues of $615.4 million for 2006, an increase of 45% over 2005 levels. Our weighted average sales price increased 20% to $8.57 per Mcfe for 2006 from $7.11 in 2005. Of our $177.8 million increase in oil and gas sales revenues, 60% came from a 2.0 million barrel increase in oil volumes produced, with the remainder attributable to higher oil prices during 2006.

Our capital expenditures more than doubled from 2005 to 2006, principally due to our acquisition of five substantial onshore properties in South Louisiana from BP America Production Company for $167.9 million in cash and the increase in our spending on drilling and development, predominantly in our South Louisiana region. Although the acquisition did not appreciably add to our 2006 production volumes, it added 58 Bcfe of proved reserves, about one-third of which were proved undeveloped, resulting in our proved undeveloped reserves increasing to 56% of total reserves at year-end 2006, compared to 50% the previous year.

Our overall costs and expenses increased in 2006 by 44%. In 2007, we will focus upon our capital efficiency by managing our costs and expenses, always a difficult task in the inflationary cost environment prevalent in the industry over the last several years, and especially over the last year when recent declines in commodity prices have not been matched by comparable declines in prices of oilfield equipment and services. The largest increase in these costs and expenses is due to increased depreciation, depletion and amortization expense, not only due to our larger depletable property base and higher production, but also due to increases in future development costs to reflect industry inflation. We expect cost pressures to continue to affect the industry throughout 2007, with tightening availability of crews as well as increasing costs of services and basic equipment.

Our year-end 2006 proved reserves were 50% crude oil, 40% natural gas, and 10% NGLs, almost identical to the percentage splits a year earlier. Our 2006 production, however, was 61% crude oil, up from 52% in 2005, which allowed us to take advantage of the over 20% increase in oil prices, while natural gas prices fell during the year. Domestic proved reserves increased at year-end 2006 to 710.4 Bcfe (87% of our total proved reserves), while proved reserves in New Zealand decreased to 106.4 Bcfe at year-end 2006, primarily attributable to 2006 production. For 2007, we are considering conducting an expanded 3-D seismic survey in New Zealand prior to continuing drilling activities.

Our financial position remains strong. Our debt to capitalization ratio was 32% at December 31, 2006, compared to 37% at year-end 2005, as debt levels increased in 2006 and retained earnings increased as a result of the current period profit, with net debt per Mcfe of $0.47 per Mcfe at year-end 2006. Our debt to PV-10 ratio increased to 14% at December 31, 2006 compared to 11% at December 31, 2005, primarily due to lower natural gas prices at year-end 2006 and an increase in our total debt, partially offset by higher oil and natural gas reserves volumes. Lower year-end commodity prices, principally natural gas, decreased our PV-10 value and standardized measure at the end of 2006 compared to the prior year-end.

Our current 2007 capital expenditure budget is $350 million to $400 million, net of minor non-core dispositions and excluding any property acquisitions. Approximately 95% of the budget is targeted for domestic activities, predominantly in our South Louisiana region, with about 5% planned for activities in the New Zealand region. For 2007, we are targeting total production to increase 7% to 10% and proved reserves to increase 4% to 6% over 2006 levels. We may also increase our capital expenditure budget if commodity

prices rise during the year or if strategic opportunities warrant. If 2007 capital expenditures exceed our cash flow from operating activities, we can fund these expenditures with our credit facility to fund these expenditures.

During 2007, we plan to further develop our inventory of properties in South Louisiana using our expertise and experience gained in expanding and producing in Lake Washington, together with significant 3-D seismic information, to exploit our other prospect areas covered by similar geological features. This broad prospect inventory will allow us to be selective in choosing drilling opportunities so we can create long-life reserves while at the same time raising our production significantly, which we did during 2006 mainly through organic production growth.

Results of Operations -- Years Ended 2006, 2005, and 2004

Revenues. Our revenues in 2006 increased by 45% compared to revenues in 2005 primarily due to increases in oil production from our Lake Washington area and increases in oil prices, and our revenues in 2005 increased by 36% compared to 2004 revenues due primarily to increases 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 2006, 2005, and 2004. Crude oil production was 61% of our production volumes in 2006, 52% in 2005, and 49% in 2004. Natural gas production was 32% of our production volumes in 2006, 40% in 2005, and 41% in 2004. Domestic production was 81% of our total production volumes in 2006, and 72% in both 2005 and 2004.

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, 2006, 2005, and 2004:

Area	Oil and Gas Sales (In millions) 2006	2005	2004	200
AWP Olmos	$ 53.7	$ 61.7	$ 49.9	7
Brookeland	15.6	20.4	18.0	2
Lake Washington	397.2	229.2	152.3	38
Masters Creek	13.3	17.9	21.0	1
Cote Blanche Island/Bay de Chene	29.3	7.4	0.0	3
Other	28.4	19.3	17.5	3
Total Domestic	$ 537.5	$ 355.9	$ 258.7	56
Rimu/Kauri	36.8	41.6	24.5	6
TAWN	27.2	26.3	28.1	7
Total New Zealand	$ 64.0	$ 67.9	$ 52.6	13
Total	$ 601.6	$ 423.8	$ 311.3	70

Oil and gas sales in 2006 increased by 42%, or $177.8 million, from the level of those revenues for 2005, and our net sales volumes in 2006 increased by 18%, or 10.6 Bcfe, over net sales volumes in 2005. Average prices for oil increased to $64.47 per Bbl in 2006 from $53.63 per Bbl in 2005. Average natural gas prices decreased to $5.05 per Mcf in 2006 from $5.23 per Mcf in 2005. Average NGL prices increased to $32.15 per Bbl in 2006 from $28.04 per Bbl in 2005.

In 2006, our $177.8 million increase in oil, NGL, and natural gas sales resulted from:

- o Volume variances that had a $101.1 million favorable impact on sales, with $108.9 million of increases attributable to the 2.0 million Bbl increase in oil sales volumes, offset by a decrease of $3.5 million due to the 0.1 million Bbl decrease in NGL sales volumes, and a decrease of $4.3 million due to the 0.8 Bcf decrease in natural gas sales volumes; and

- o Price variances that had a $76.7 million favorable impact on sales, of which $78.0 million was attributable to the 20% increase in average oil prices received, and $2.9 million was attributable to the 15% increase in NGL prices, offset by a decrease of $4.2 million attributable to the 3% decrease in natural gas prices.

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.

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.

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

	Sales Volume				Average Sales	
	Oil	NGL	Gas	Combined	Oil	NGL
	(MBbl)	(MBbl)	(Bcf)	(Bcfe)	(Bbl)	(Bbl)
2004:						
First	1,124	277	5.9	14.3	$ 34.14	$ 22.3
Second	1,142	269	5.8	14.3	$ 37.24	$ 18.8
Third	1,076	251	6.0	13.9	$ 41.99	$ 23.3
Fourth	1,380	243	6.1	15.9	$ 46.33	$ 26.0
Total	4,722	1,040	23.7	58.3	$ 40.24	$ 22.5
2005:						
First	1,321	223	6.3	15.5	$ 47.66	$ 26.7
Second	1,426	209	6.1	15.9	$ 50.24	$ 22.9
Third	1,059	204	5.9	13.5	$ 59.66	$ 31.8
Fourth	1,353	202	5.3	14.7	$ 58.31	$ 30.8
Total	5,159	838	23.6	59.6	$ 53.63	$ 28.0
2006:						
First	1,611	152	6.0	16.5	$ 60.83	$ 30.3
Second	1,636	138	5.6	16.3	$ 69.63	$ 29.7
Third	1,992	220	5.5	18.8	$ 69.62	$ 36.1
Fourth	1,951	203	5.7	18.6	$ 57.88	$ 30.7
Total	7,190	713	22.8	70.2	$ 64.47	$ 32.1

In 2006, we settled all insurance claims with our insurers relating to hurricanes Katrina and Rita for approximately $30.5 million and entered into a confidential final settlement agreement. The receipt of these amounts resulted in a benefit of $7.7 million in 2006 recorded in "Price-risk management and other, net," for the portion of the above referenced settlement, which we have determined to be non-property damage related claims. Approximately $22.8 million of the above referenced settlement was determined to be property damage related claims. We recorded $14.1 million of the property related settlement as a reduction to "Proved properties" on the accompanying consolidated balance sheet, as this related to reimbursement of capital costs we incurred. We also recorded $8.7 million of the property related settlement as a reduction to "Lease operating cost" on the accompanying consolidated statement of income, as this related to reimbursement of repair costs which had been expensed as incurred. In the accompanying consolidated statement of cash flows, we have recorded the reimbursement which reduced "Proved properties" as a reduction of "Net Cash Used in Investing Activities" and the remainder of the insurance settlement was recorded as an increase to "Net Cash Provided by Operating Activities."

Costs and Expenses. Our expenses in 2006 increased $108.4 million, or 44%, compared to 2005 expenses. The majority of the increase was due to a $61.8 million increase in DD&A, a $23.3 million increase in severance and other taxes, and a $15.2 million increase in lease operating costs, all of which are primarily due to increased production volumes in 2006. Increased commodity prices also increased severance and other taxes, and higher full cost pool

balances increased DD&A, offset somewhat by increased reserves volumes in 2006. 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 2006 general and administrative expenses, net, increased $9.1 million, or 41%, from the level of such expenses in 2005, while 2005 general and administrative expenses, net, increased $4.4 million, or 25%, over 2004 levels. The increase in both 2006 and 2005 were primarily due to increased salaries and burdens associated with our expanded workforce. Costs also increased in 2006 as a result of expensing stock options and increased restricted stock grants, and increased in 2005 due to restricted stock compensation. For the years 2006, 2005, and 2004, our capitalized general and administrative costs totaled $28.3 million, $18.8 million, and $13.1 million, respectively. Our net general and administrative expenses per Mcfe produced increased to $0.45 per Mcfe in 2006 from $0.37 per Mcfe in 2005 and $0.30 per Mcfe in 2004. The portion of supervision fees recorded as a reduction to general and administrative expenses was $8.8 million for 2006, $7.8 million for 2005, and 5.8 million for 2004.

DD&A increased $61.8 million, or 58%, in 2006 from 2005 levels, while 2005 DD&A increased $25.9 million, or 32%, from 2004 levels. Domestically, DD&A increased $58.1 million in 2006 due to increases in the depletable oil and gas property base and higher production, partially offset by higher reserves volumes. In New Zealand, DD&A increased by $3.7 million in 2006 due to an increase in the depletable oil and gas property base and lower reserves. In 2005, our domestic DD&A increased $18.8 million 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. Our DD&A rate per Mcfe of production was $2.41 in 2006, $1.80 in 2005, and $1.40 in 2004, resulting from increases in per unit cost of reserves additions.

We recorded $1.0 million, $0.8 million, and $0.7 million of accretions to our asset retirement obligation in 2006, 2005, and 2004, respectively.

Our lease operating costs per Mcfe produced were $0.89 in 2006, $0.79 in 2005 and $0.71 in 2004. Our lease operating costs in 2006 increased $15.2 million, or 32%, over the level of such expenses in 2005, while 2005 costs increased $6.1 million, or 15% over 2004 levels. Approximately $15.0 million of the increase in lease operating costs during 2006 was related to our domestic operations, which increased primarily due to increased production and was also impacted by increased well insurance premiums. Our lease operating cost in New Zealand increased in 2006 by $0.1 million due to increases in well operating costs and storage and handling costs.

Severance and other taxes increased $23.3 million, or 55%, over 2005 levels, while in 2005 these taxes increased $11.8 million, or 39% over 2004 levels. The increases were due primarily to higher commodity prices and increased Lake Washington 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 10.9%, 10.0% and 9.8% in 2006, 2005 and 2004, respectively.

Our total interest cost in 2006 was $32.8 million, of which $9.2 million was capitalized. 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. 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 both 2006 and 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 the same $19.2 million in 2006, 2005, and 2004. 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. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.5 million in 2006, $1.0 million in 2005, and $1.5 million in 2004. Other interest cost was $0.1 million in 2006. We capitalize a portion of interest related to unproved properties. The decrease of interest expense in 2006 was primarily due to an increase in capitalized interest costs, partially offset by an increase in credit facility interest. 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.

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 38.4% for 2006, 35.1% for 2005 and 32.5% for 2004. The effective tax rate for 2006 was higher than the statutory rate primarily because of state income taxes and a valuation allowance, partially offset by favorable adjustments for the currency effect on the New Zealand deferred tax calculation. For 2005, the effective rate was about the same as the statutory rate as state income taxes and the currency effect adjustments essentially offset. For 2004, the effective rate was less than the statutory rate due to favorable adjustments for currency effect and corrections to tax basis amounts, partially offset by deferred state income taxes.

Net Income. Our net income in 2006 of $161.6 million was 40% higher than our 2005 net income of $115.8 million due to higher oil prices and increased production.

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.

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter as of December 31, 2006 are as follows:

	2007	2008	2009	2010	20
				(In thousands)	
Non-cancelable operating leases(1)	$ 5,345	$ 5,321	$ 3,334	$ 3,293	$ 3
Asset retirement obligation(2)	1,650	2,313	2,019	2,110	2
Computer System Implementation	3,261	--	--	--	
Construction costs	5,223	--	--	--	
Drilling rigs, seismic and pipe inventory	28,873	--	--	--	
7-5/8% senior notes due 2011(3)	--	--	--	--	150
9-3/8% senior subordinated notes due 2012(3)	--	--	--	--	
Credit facility(4)	--	--	--	--	31
Total	$ 44,352	$ 7,634	$ 5,353	$ 5,403	$ 18

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

(2) Amounts shown by year are the fair values at December 31, 2006.

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

(4) The credit facility expires in October 2011 and these amounts exclude a $0.8 million standby letter of credit outstanding under this facility.

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, and 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 2006, we relied upon our net cash provided by operating activities of $424.9 million, credit facility borrowings of $31.4 million, property sales proceeds of $24.7 million, and cash balances to fund capital expenditures of $557.5 million including $194.3 million of acquisitions. During 2005, we largely relied upon our net cash provided by operating activities of $285.3 million to fund capital expenditures of $264.5 million including $28.9 million of acquisitions.

Net Cash Provided by Operating Activities. For 2006, our net cash provided by operating activities was $424.9 million, representing a 49% increase as compared to $285.3 million generated during 2005. The $139.6 million increase in 2006 was primarily due to an increase of $177.8 million in oil and gas sales, attributable to higher oil prices and production, offset in part by higher lease operating costs and severance taxes due to higher oil prices and higher domestic production. In 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.

Accounts Receivable. 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 both December 31, 2006 and 2005, we had an allowance for doubtful accounts of less than $0.1 million. The allowance for doubtful accounts has been deducted from the total "Accounts receivable" balances on the accompanying balance sheets.

Existing Credit Facility. We had borrowings of $31.4 million under our bank credit facility at December 31, 2006, and no outstanding borrowings at December 31, 2005. Our bank credit facility at December 31, 2006 consisted of a $500.0 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, 2006. 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 operations, financial condition, prospects or properties, and would impair the 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 declined from a surplus of $16.6 million at December 31, 2005, to a deficit of $53.4 million at December 31, 2006. The decrease primarily resulted from a decrease in cash and cash equivalents due to property acquisitions during the fourth quarter of 2006.

Debt Maturities. Our credit facility, with a balance of $31.4 million at December 31, 2006, extends until October 3, 2011. 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.

On or after May 1, 2007, we are entitled to redeem our $200.0 million of 9-3/8% senior subordinated notes at a redemption price, plus accrued and unpaid interest, of 104.688% of principal. If these notes were redeemed, we would most likely use a combination of drawings upon our credit facility, cash flows from operations, and the use of debt and/or equity offerings to fund any such redemption.

Capital Expenditures. In 2006 we relied upon our net cash provided by operating activities of $424.9, credit facility borrowings of $31.4 million, property sales proceeds of $24.7 million, and cash balances to fund capital expenditures of $557.5 million including $194.3 million of acquisitions. Our total capital expenditures of approximately $557.5 million in 2006 included:

Domestic expenditures of $502.3 million as follows:

- $214.9 million for drilling and developmental activity costs, predominantly in our South Louisiana area;
- $200.5 million for acquisitions of properties, primarily in our South Louisiana area;
- $20.5 million on exploratory drilling;
- $51.1 million of domestic prospect costs, principally prospect leasehold, 3-D seismic activity, and geological costs of unproved prospects;
- $15.3 million primarily for leasehold improvements, computer equipment, software, furniture, and fixtures;

New Zealand expenditures of $55.2 million as follows:

- $28.8 million for drilling costs and developmental activity costs, predominantly in our Rimu/Kauri area;
- $15.7 million on exploratory drilling;
- $10.4 million on prospect costs, principally prospect leasehold, seismic and geological costs of unproved properties;
- $0.3 million for computer equipment, software, furniture, and fixtures.

We continue to spend considerable time and capital on facility capacity upgrades in the Lake Washington field, and increased facility capacity at year-end 2006 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. During 2006, we began planning for the addition of a fourth production platform which will increase our processing capacity another 10,000 barrels per day by mid-2008.

We completed 45 of 63 wells in 2006, for a success rate of 71%. Domestically, we completed 42 of 49 development wells for a success rate of 86% and were unsuccessful on six exploratory wells, including five very shallow exploration wells in the AWP Olmos area which cost $0.5 million in the aggregate, and one non-operated well in Alaska. A total of 21 development wells were drilled in the Lake Washington area, of which 18 were completed, and 15 development wells were drilled in the AWP Olmos area, of which 14 were completed. We also drilled six development wells in the Bay de Chene area, of which three were completed, drilled three successful development wells in each of the Cote Blanche Island and South Bearhead Creek areas, and drilled one successful development well in the Brookeland area. In New Zealand, we completed three of four development wells but were unsuccessful on four exploratory wells.

Our capital expenditures were approximately $264.5 million in 2005 and $171.1 million in 2004. In 2005, we relied upon our net cash provided by operating activities of $285.3 million to fund capital expenditures of $264.5 million, including acquisitions of $28.9 million. 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 $198.3 million, including acquisitions of $27.2 million. Our total capital expenditures in 2005 of approximately $264.5 million included:

Domestic expenditures of $215.8 million as follows:

o $111.0 million for drilling and developmental activity costs, predominantly in our Lake Washington area;

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o $29.6 million on property acquisitions, including $28.9 million to acquire properties in the South Bearhead Creek field;

o $36.8 million on exploratory drilling, mainly in our Lake Washington area;

o $34.4 million of prospect costs, principally prospect leasehold, 3-D seismic activity, and geological costs of unproved prospects;

o $3.6 million primarily for a field office building, computer equipment, software, furniture, and fixtures;

o $0.3 million on gas processing plants in the Brookeland and Masters Creek areas; and o less than $0.1 million on field compression facilities.

New Zealand expenditures of $48.7 million as follows:

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

o $13.6 million on exploratory drilling;

o $6.9 million on prospect costs, principally prospect leasehold, seismic and geological costs of unproved properties;

o $0.8 million on gas processing plants; and

o $0.2 million for computer equipment, software, furniture, and fixtures.

In 2005, we participated in drilling 45 domestic development wells and nine domestic exploratory wells, of which 37 development wells and five exploratory wells were completed. In New Zealand we drilled five development wells, of which two were completed, and five exploratory wells, of which one was completed.

New Accounting Pronouncements

Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123 (R), "Share-Based Payment" (SFAS No. 123R) utilizing the modified prospective approach. Prior to the adoption of SFAS No. 123R, we accounted for stock option grants in accordance with Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" (the intrinsic value method), and accordingly, recognized no compensation expense for employee stock option grants. Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006 as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized for the year ended December 31, 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting the new standard. As a result of adopting SFAS No. 123R on January 1, 2006, our income before taxes, net income and basic and diluted earnings per share for the year ended December 31, 2006, were $3.4 million, $2.8 million, $0.09, and $0.09 lower, respectively. Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to one recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in "General and Administrative, net" in the accompanying consolidated statements of income.

In September 2006, the SEC released SAB 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). SAB 108 addresses the process of quantifying financial statement misstatements, such as assessing both the carryover and reversing effects of prior year misstatements on the current year financial statements. SAB 108 became effective for our fiscal year ended December 31, 2006. The adoption of this statement had no impact on our financial position or results of operations.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109." This Interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, "Accounting for Income Taxes." FIN No. 48 prescribes a threshold condition that a tax position must meet for any of the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding derecognition, classification and disclosure of these uncertain tax positions. FIN No. 48 is effective for fiscal years beginning after December 15, 2006. The adoption of this Interpretation is not expected to have a material impact on its financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 addresses how companies should approach measuring fair value when required by GAAP; it does not create or modify any current GAAP requirements to apply fair value accounting. SFAS No. 157 provides a single definition for fair value that is to be applied consistently for all accounting applications, and also generally describes and prioritizes, according to reliability, the methods and inputs used in valuations. SFAS No. 157 prescribes various disclosures about financial statement categories and amounts which are measured at fair value, if such disclosures are not already specified elsewhere in GAAP. The new measurement and disclosure requirements of SFAS No. 157 are effective for us in the first quarter 2008. The Company has not yet determined what impact, if any, this statement will have on its financial position or results of operations.

Proved Oil and Gas Reserves

At year-end 2006, our total proved reserves were 816.8 Bcfe with a PV-10 Value of $2.7 billion (PV-10 is a non-GAAP measure, see the section titled "Oil and Natural Gas Reserves" in our Property section for a reconciliation of this non-GAAP measure to the closest GAAP measure, the standardized measure). In 2006, our proved natural gas reserves increased 36.7 Bcf, or 13%, while our proved oil reserves increased 4.0 MMBbl, or 6%, and our NGL reserves decreased 0.9 MMBbl, or 6%, for a total equivalent increase of 55.1 Bcfe, or 7%. In 2005, our proved natural gas reserves decreased by 30.8 Bcf, or 10%, while our proved oil reserves decreased by 0.7 MMBbl, or 1%, and our NGL reserves decreased by 0.5 MMBbl, or 3%, for a total equivalent decrease of 38.1 Bcfe, or 5%. We added reserves over the past three years through both our drilling activity and purchases of minerals in place. Through drilling we added 72.8 Bcfe (1.2 Bcfe of which came from New Zealand) of proved reserves in 2006, 31.6 Bcfe (2.0 Bcfe of which came from New Zealand) in 2005, and 7.2 Bcfe (all of which was domestic) in 2004. Through acquisitions we added 77.8 Bcfe of proved reserves in 2006, 28.9 Bcfe in 2005, and 43.4 Bcfe in 2004. At year-end 2006, 44% of our total proved reserves were proved developed, compared with 50% at year-end 2005 and 56% at year-end 2004.

Despite increased reserves volumes, the PV-10 Value of our total proved reserves at year-end 2006 decreased 15% from the PV-10 Value at year-end 2005. Gas prices decreased in 2006 to $5.46 per Mcf from $8.94 per Mcf at year-end 2005, compared to $5.16 per Mcf at year-end 2004. Oil prices increased in 2006 to $60.41 per Bbl from $60.12 per Bbl at year-end 2005, compared to $41.07 in 2004. 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 reserves 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 and assumptions 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,

- estimates in the calculation of stock compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,
- 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 new accounting pronouncements, 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 2006, 2005, and 2004, such internal costs capitalized totaled $28.3 million, $18.8 million, and $13.1 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the years 2006, 2005, and 2004, capitalized interest on unproved properties totaled $9.2 million, $7.2 million, and $6.5 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, 2006 consisted of natural gas price floors with strike prices higher than the period-end price and 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. If we have declines in our oil and gas reserves volumes, which also reduce our estimate of discounted future net cash flows from proved oil and gas reserves, a non-cash write-down of our 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 2006, 2005 and 2004, we recognized net gains of $4.0 million, and net losses of $1.1 million and $1.3 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, 2006, the Company had recorded $0.3 million, net of taxes of less than $0.2 million, of derivative gains 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 2006, 2005, and 2004 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 three months when the forecasted sale of hedged production occurs.

At December 31, 2006, we had in place price floors in effect for February 2007 through the March 2007 contract month for natural gas, that cover a portion of our domestic natural gas production for February 2007 to March 2007. The natural gas price floors cover notional volumes of 800,000 MMBtu, with a weighted average floor price of $7.00 per MMBtu. Our natural gas price floors in place at December 31, 2006 are expected to cover approximately 25% to 30% of our estimated domestic natural gas production from February 2007 to March 2007.

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 the 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, 2006, was $0.7 million and is recognized on the accompanying balance sheet in "Other current assets."

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, 2006, we did not have any material natural gas imbalances.

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 which increases or decreases the full cost pool. 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.

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

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 SFAS 123R, "Share-Based Compensation," and related interpretations.

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 were 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 the same $0.2 million in 2006, 2005 and 2004, 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 $0.1 million per year in 2006 and 2005, and $0.2 million in 2004, and are recorded as reductions in general and administrative, net. As of December 31, 2006, the remaining two partnerships have been dissolved.

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 aunt of the Company's Chairman of the Board and Chief Executive Officer. We paid approximately $0.5 million to Tec-Com for such services pursuant to the terms of the contract between the parties in 2006, and $0.4 million per year in 2005 and 2004. 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.

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 of future 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, 2006, we had in place price floors in effect through the March 2007 contract month for natural gas. The natural gas price floors cover notional volumes of 800,000 MMBtu, with a weighted average floor price of $7.00 per MMBtu. Our natural gas price floors in place at December 31, 2006 are expected to cover approximately 25% to 30% of our domestic natural gas production in February 2007 and March 2007. The fair value of these instruments at December 31, 2006, was $0.7 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 2007 would be their fair value at December 31, 2006 of $0.7 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, 2006, we had borrowings of $31.4 million 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 83 basis points and would not have a material adverse effect on our 2007 cash flows based on this same level or a modest level of borrowing.

Income Tax Carryforwards. We had significant foreign net operating loss carryforwards at December 31, 2006. The foreign net operating losses have no expiration period, but would be cancelled if a change in control occurred at either the subsidiary or ultimate parent company level. Other loss carryforwards consist of state net operating losses and capital losses. The Company has not recorded a valuation allowance against the deferred tax assets attributable to the net operating carryovers at December 31, 2006, as management estimates that it is more likely than not that these assets will be fully utilized before they expire. The foreign net operating loss has no expiration period, but it would be cancelled if a change in control occurred at either the subsidiary or ultimate parent company level. A valuation allowance has been applied 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.

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, 2006 and 2005, 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, 2006 and 2005, the fair values of our senior subordinated notes due 2012 were $211.0 million, or 105.5% of face value, and $214.5 million, or 107.25% of face value, respectively. Based upon quoted market prices as of

December 31, 2006 and 2005, the fair values of our senior notes due 2011 were $152.6 million, or 101.75% of face value, and $153.8 million, or 102.5% of face value. The carrying value of our senior subordinated notes due 2012 was $200.0 million at December 31 for both 2006 and 2005. The carrying value of our senior notes due 2011 was $150.0 million at December 31 for both 2006 and 2005.

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 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

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, 2006. 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, 2006.

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, 2006. 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, 2006 appears on the following page.

Report of Independent Registered Public Accounting Firm

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 and subsidiaries maintained effective internal control over financial reporting as of December 31, 2006, 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 and subsidiaries maintained effective internal control over financial reporting as of December 31, 2006, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Swift Energy Company and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, 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, 2006 and 2005, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2006 and our report dated February 27, 2007 expressed an unqualified opinion thereon.

ERNST & YOUNG. LLP

Houston, Texas
February 27, 2007

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Report of Independent Registered Public Accounting Firm

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, 2006 and 2005, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2006. 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, 2006 and 2005, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2006, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated financial statements, in 2006 the Company changed its method of accounting for stock-based compensation.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Swift Energy Company and subsidiaries internal control over financial reporting as of December 31, 2006, 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, 2007 expressed an unqualified opinion thereon.

ERNST & YOUNG LLP

Houston, Texas
February 27, 2007

Consolidated Balance Sheets
Swift Energy Company and Subsidiaries

		December 31, 2006
ASSETS		
Current Assets:		
Cash and cash equivalents	$	1,058,05
Accounts receivable-		
Oil and gas sales		63,935,44
Joint interest owners		1,843,82
Other Receivables		1,231,38
Deferred Tax Asset		2,383,17
Other current assets		22,121,16
Total Current Assets		92,573,04
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties		2,264,831,63
Unproved properties		112,136,83
		2,376,968,47
Furniture, fixtures, and other equipment		28,040,40
		2,405,008,87
Less - Accumulated depreciation, depletion, and amortization		(921,696,71
		1,483,312,16
Other Assets:		
Debt issuance costs		7,382,26
Restricted assets		2,414,28
		9,796,55
	$	1,585,681,75
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$	74,425,08
Accrued capital costs		55,282,00
Accrued interest		8,764,27
Undistributed oil and gas revenues		7,503,92
Total Current Liabilities		145,975,28

Long-Term Debt	381,400,00
Deferred Income Taxes	224,966,59
Asset Retirement Obligation	33,694,60
Lease Incentive Obligation	1,728,29
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, 30,170,004 and 29,458,974 shares issued, and 29,742,918 and 29,009,530 shares outstanding, respectively	301,70
Additional paid-in capital	387,555,79
Treasury stock held, at cost, 427,086 and 449,444 shares, respectively	(6,124,94
Unearned compensation	--
Retained earnings	415,868,09
Accumulated other comprehensive income (loss), net of income tax	316,32
	797,916,972
	$ 1,585,681,75

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Income
Swift Energy Company and Subsidiaries

	Year Ended December	
	2006	2005
Revenues:		
Oil and gas sales	$ 601,551,368	$ 423,766,245
Price-risk management and other, net	13,889,862	(539,756)
	615,441,230	423,226,489
Costs and Expenses:		
General and administrative, net	31,316,644	22,176,362
Depreciation, depletion, and amortization	169,295,774	107,477,787
Accretion of asset retirement obligation	1,034,322	761,042
Lease operating cost	62,474,619	47,321,841
Severance and other taxes	65,452,043	42,176,505
Interest expense, net	23,581,663	24,873,401
Debt retirement cost	---	---
	353,155,065	244,786,938

Income Before Income Taxes	262,286,165	178,439,551
Provision for Income Taxes	100,720,825	62,661,095
Net Income	$ 161,565,340	$ 115,778,456
Per Share Amounts-		
Basic: Net Income	$ 5.52	$ 4.06
Diluted: Net Income	$ 5.38	$ 3.95
Weighted Average Shares Outstanding	29,265,366	28,496,275

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Stockholders' Equity
Swift Energy Company and Subsidiaries

	Common Stock (1)	Additional Paid-in Capital	Treasury Stock	Unearned Compensation	Retained Earnings
Balance, December 31, 2003	$ 280,111	$ 334,865,204	$ (7,558,093)	$ -	$ 70,073,384
Stock issued for benefit plans (46,150 shares)	-	166,298	661,848	-	-
Stock options exercised (509,105 shares)	5,091	4,260,882	-	-	-
Tax benefits from exercise of stock Options	-	1,956,555	-	-	-
Employee stock purchase plan (50,418 shares)	504	502,097	-	-	-
Grants of restricted stock (100,900 shares)	-	1,785,262	-	(1,785,262)	
Amortization of restricted stock compensation	-	-	-	56,677	-
Comprehensive income:					
Net income	-	-	-	-	68,450,917
Change in fair value of other comprehensive income	-	-	-	-	-
Total comprehensive					

income	-	-	-	-	-
Balance, December 31, 2004	$ 285,706	$ 343,536,298	$ (6,896,245)	$ (1,728,585)	$ 138,524,301
Stock issued for benefit plans (31,424 shares)	-	435,134	450,659	-	-
Stock options exercised (840,847 shares)	8,409	9,804,555	-	-	-
Tax benefits from exercise of stock options	-	4,366,236	-	-	-
Employee stock purchase plan (32,495 shares)	325	642,354	-	-	-
Issuance of restricted stock (15,000 shares)	150	-	-	-	-
Grants of restricted stock (158,500 shares)	-	6,668,608	-	(6,072,008)	-
Forfeitures of restricted stock	-	(367,490)	-	367,490	-
Amortization of restricted stock compensation	-	-	-	1,583,283	-
Comprehensive income:					
Net income	-	-	-	-	115,778,456
Change in fair value of other comprehensive loss	-	-	-	-	-
Total comprehensive income	-	-	-	-	-
Balance, December 31, 2005	$ 294,590	$ 365,085,695	$ (6,445,586)	$ (5,849,820)	$ 254,302,757
Stock issued for benefit plans (22,358 shares)	-	714,049	320,642	-	-
Stock options exercised (652,829 shares)	6,528	11,830,763	-	-	-
Adoption of SFAS No.123R	-	(5,875,280)	-	5,849,820	-
Excess tax benefits from stock-based awards	-	4,811,362	-	-	-
Employee stock purchase plan (22,425 shares)	224	671,106	-	-	-
Issuance of restricted stock (35,776 shares)	358	(358)	-	-	-
Amortization of stock compensation	-	10,318,460	-	-	-
Comprehensive Income:					
Net income	-	-	-	-	161,565,340
Other comprehensive income	-	-	-	-	-
Total comprehensive income	-	-	-	-	-
Balance, December 31, 2006	$ 301,700	$ 387,555,797	$ (6,124,944)	$ -	$ 415,868,097

(1)$.01 par value.

See accompanying Notes to Consolidated Financial Statements.

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Consolidated Statements of Cash Flows
Swift Energy Company and Subsidiaries

	Year Ended December	
	2006	2005
Cash Flows from Operating Activities:		
Net income	$ 161,565,340	$ 115,778,
Adjustments to reconcile net income to net cash provided by operating activities-		
Depreciation, depletion, and amortization	169,295,774	107,477,
Accretion of asset retirement obligation	1,034,322	761,
Deferred income taxes	90,027,972	61,911,
Stock-based compensation expense	6,905,260	1,450,
Debt retirement cost - cash and non-cash	---	
Other	3,225,561	362,
Change in assets and liabilities-		
Increase in accounts receivable	(19,178,818)	(6,778,
Increase in accounts payable and accrued liabilities	10,905,914	5,071,
Increase (decrease) in income taxes payable	883,639	
Increase (decrease) in accrued interest	256,082	(700,
Net Cash Provided by Operating Activities	424,921,046	285,333,
Cash Flows from Investing Activities:		
Additions to property and equipment	(363,222,113)	(235,547,
Proceeds from the sale of property and equipment	24,678,020	7,296,
Acquisition of properties	(194,269,399)	(28,927,
Net cash received as operator of oil and gas properties	9,385,700	17,797,
Net cash received (distributed) as operator of partnerships	409,816	(948,
Other	(528,415)	255,
Net Cash Used in Investing Activities	(523,546,391)	(240,074,
Cash Flows from Financing Activities:		
Proceeds from long-term debt	---	
Payments of long-term debt	---	
Net proceeds from (payments of) bank borrowings	31,400,000	(7,500,
Net proceeds from issuances of common stock	12,508,621	10,325,
Excess tax benefits from stock-based awards	3,327,713	
Payments of debt retirement costs	---	
Payments of debt issuance costs	(557,500)	
Net Cash Provided by Financing Activities	46,678,834	2,825,
Net Increase (Decrease) in Cash and Cash Equivalents	$ (51,946,511)	$ 48,084,

Cash and Cash Equivalents at Beginning of Year	53,004,562	4,920,
Cash and Cash Equivalents at End of Year	$ 1,058,051	$ 53,004,
Supplemental Disclosures of Cash Flows Information:		
Cash paid during year for interest, net of amounts capitalized	$ 22,690,797	$ 24,482,
Cash paid during year for income taxes	$ 9,779,500	$ 750,

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 ("Swift Energy") 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 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 Stock Exchange. 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 four 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 and assumptions 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,
- estimates in the calculation of stock compensation expense,
- estimates of our ownership in properties prior to final division of interest determination,
- 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 new accounting pronouncements, 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 2006, 2005, and 2004, such internal costs capitalized totaled $28.3 million, $18.8 million, and $13.1 million, respectively. Interest costs are also capitalized to unproved oil and gas properties. For the years 2006, 2005, and 2004, capitalized interest on unproved properties totaled $9.2 million, $7.2 million, and $6.5 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 property-by-property 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, 2006 consisted of natural gas price floors with strike prices higher than the period-end price but 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, 2006, we did not have any material natural gas imbalances.

Accounts Receivable. 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, 2006 and 2005, we had an allowance for doubtful accounts of approximately $0.1 million. 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, 2006, was $3.6 million, net of accumulated amortization of $2.0 million. The issuance costs associated with our revolving credit facility, which was extended in October 2006, have been capitalized and are being amortized over the life of the facility. The balance of revolving credit facility issuance costs at December 31, 2006, was $1.0 million, net of accumulated amortization of $2.0 million. The 7-5/8% senior notes due 2011 mature on July 15, 2011, and the balance of their issuance costs at December 31, 2006, was $2.8 million, net of accumulated amortization of $1.2 million.

Settlement of Insurance Claims. In 2006, we settled all insurance claims with our insurers relating to hurricanes Katrina and Rita for approximately $30.5 million and entered into a confidential final settlement agreement. The receipt of these amounts resulted in a benefit of $7.7 million in 2006 recorded in "Price-risk management and other, net," for the portion of the above referenced settlement, which we have determined to be non-property damage related claims. Approximately $22.8 million of the above referenced settlement was determined to be property damage related claims. We recorded $14.1 million of the property related settlement as a reduction to "Proved properties" on the accompanying consolidated balance sheet, as this related to reimbursement of capital costs we incurred. We also recorded $8.7 million of the property related settlement as a reduction to "Lease operating cost" on the accompanying consolidated statement of income, as this related to reimbursement of repair costs which had been expensed as incurred. In the accompanying consolidated statement of cash flows, we have recorded the reimbursement which reduced "Proved properties" as a reduction of "Net Cash Used in Investing Activities" and the remainder of the insurance settlement was recorded as an increase to "Net Cash Provided by Operating Activities."

Limited Partnerships. In 2006, we served as managing general partner for two private limited partnerships, and during fiscal 2006, 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 were dissolved in December 2006.

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 2006, 2005 and 2004, we recognized net gains of

$4.0 million and net losses of $1.1 million and $1.3 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, 2006, the Company had recorded $0.3 million, net of taxes of less than $0.2 million, of derivative gains 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 2006, 2005, and 2004 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 three months when the forecasted sale of hedged production occurs.

At December 31, 2006, we had in place price floors in effect for February 2007 through the March 2007 contract month for natural gas, that cover a portion of our domestic natural gas production for February 2007 to March 2007. The natural gas price floors cover notional volumes of 800,000 MMBtu, with a weighted average floor price of $7.00 per MMBtu. Our natural gas price floors in place at December 31, 2006 are expected to cover approximately 25% to 30% of our estimated domestic natural gas production from February 2007 to March 2007.

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 the 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, 2006, was $0.7 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. The total amount of supervision fees charged to the wells we operate was $8.8 million in 2006, $7.8 million in 2005, and $5.8 million in 2004.

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, 2006 (in thousands)	Balance at December 31, 2005 (in thousands)
Materials, Supplies and Tubulars................	$ 10,611	$ 8,494
Crude Oil	474	916
Total	$ 11,085	$ 9,410

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.

Accounts Payable and Accrued Liabilities. Included in "Accounts payable and accrued liabilities," on the accompanying balance sheets, at December 31, 2006 and 2005 are liabilities of approximately $13.9 million and $9.9 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 2006 and 2005, oil and gas sales to Shell Oil Company and affiliates were $180.4 million and $179.9 million, or 30% and 42% of total oil and gas sales, respectively. During 2006, Chevron Corporation and its affiliates accounted for $193.9 million or 32% of our total oil and gas sales. During 2004, oil and gas sales to Shell Oil Company and affiliates, both domestically and in New Zealand, were $149.2 million, or 48% 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, 2006 and 2005, 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, 2006 and 2005, the fair values of our senior subordinated notes due 2012 were $211.0 million, or 105.5% of face value, and $214.5 million, or 107.25% of face value, respectively. Based upon quoted market prices as of December 31, 2006 and 2005, the fair values of our senior notes due 2011 were $152.6 million, or 101.75% of face value, and $153.8 million, or 102.5% of face value. The carrying value of our senior subordinated notes due 2012 was $200.0 million at December 31 for both 2006 and 2005. The carrying value of our senior notes due 2011 was $150.0 million at December 31 for both 2006 and 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, 2006, we recorded $0.3 million, net of taxes of less than $0.2 million, of derivative gains 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 2006 were as follows:

	Gross Value	Tax Effect	Net of T
Other comprehensive loss at December 31, 2005	$ (110,094)	$ 40,625	$
Change in fair value of cash flow hedges	4,672,043	(1,733,328)	
Effect of cash flow hedges settled during the period	(4,059,052)	1,506,128	(
Other comprehensive income at December 31, 2006	$ 502,897	$ (186,575)	$

Total comprehensive income was $162.0 million, $115.3 million, and $69.2 million for 2006, 2005, and 2004, respectively.

Stock Based Compensation. Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123 (R), "Share-Based Payment" (SFAS No. 123R) utilizing the modified prospective approach. Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006 as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized for the year ended December 31, 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting the new standard.

We have three stock-based compensation plans, which are described more fully in Note 6.

Prior to 2006, we accounted for those plans under the recognition and measurement principles of APB Opinion No. 25, "Accounting for Stock Issued to Employees," and related interpretations. No stock-based employee compensation cost is reflected in net income for employee stock options prior to 2006, 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
Net Income:	As Reported	$115,778,456	$68,450,9
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(2,712,441)	(3,557,5
	Pro Forma	$113,066,015	$64,893,3
Basic EPS:	As Reported	$4.06	$2.
	Pro Forma	$3.97	$2.
Diluted EPS:	As Reported	$3.95	$2.
	Pro Forma	$3.86	$2.

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 2006, 2005, and 2004, respectively: no dividend yield; expected volatility factors of 39.3%, 41.6%, and 38.6%; risk-free interest rates of 4.8%, 3.8%, and 3.6%; and expected lives of 4.8, 3.9, and 5.4 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.

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 which increases or decreases the full cost pool. 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.

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

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 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 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
Accretion expense for 2006	1,034,322
Liabilities incurred for new wells and facilities construction	684,175
Liabilities incurred for acquisitions	12,207,480
Reductions due to sold and abandoned wells	(334,591)
Revisions in estimated cash flows	1,467,673
Increase due to currency exchange rate fluctuations	45,027
Asset Retirement Obligation as of December 31, 2006	$ 34,460,453

At December 31, 2006 and 2005, approximately $0.8 million and $0.3 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. Effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards (SFAS) No. 123 (R), "Share-Based Payment" (SFAS No. 123R) utilizing the modified prospective approach. Prior to the adoption of SFAS No. 123R, we accounted for stock option grants in accordance with Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees" (the intrinsic value method), and accordingly, recognized no compensation expense for employee stock option grants. Under the modified prospective approach, SFAS No. 123R applies to new awards and to awards that were outstanding on January 1, 2006 as well as those that are subsequently modified, repurchased or cancelled. Under the modified prospective approach, compensation cost recognized for the year ended December 31, 2006 includes compensation cost for all share-based awards granted prior to, but not yet vested as of January 1, 2006, based on the grant-date fair value estimated in accordance with the original provisions of SFAS No. 123, and compensation cost for all share-based awards granted subsequent to January 1, 2006, based on the grant-date fair value estimated in accordance with the provisions of SFAS No. 123R. Prior periods were not restated to reflect the impact of adopting the new standard. As a result of adopting SFAS No. 123R on January 1, 2006, our income before taxes, net income and basic and diluted earnings per share for the year ended December 31, 2006, were $3.4 million, $2.8 million, $0.09, and $0.09 lower, respectively. Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to one recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in "General and Administrative, net" in the accompanying consolidated statements of income.

In September 2006, the SEC released SAB 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements" (SAB 108). SAB 108 addresses the process of quantifying financial statement misstatements, such as assessing both the carryover and reversing effects of prior year misstatements on the current year financial statements. SAB 108 became effective for our fiscal year ended December 31, 2006. The adoption of this statement had no impact on our financial position or results of operations.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes - an interpretation of FASB Statement No. 109." This Interpretation provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, "Accounting for Income Taxes." FIN No. 48 prescribes a threshold condition that a tax position must meet for any of

the benefit of the uncertain tax position to be recognized in the financial statements. Guidance is also provided regarding derecognition, classification and disclosure of these uncertain tax positions. FIN No. 48 is effective for fiscal years beginning after December 15, 2006. The adoption of this Interpretation is not expected to have a material impact on its financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements. SFAS No. 157 addresses how companies should approach measuring fair value when required by GAAP; it does not create or modify any current GAAP requirements to apply fair value accounting. SFAS No. 157 provides a single definition for fair value that is to be applied consistently for all accounting applications, and also generally describes and prioritizes, according to reliability, the methods and inputs used in valuations. SFAS No. 157 prescribes various disclosures about financial statement categories and amounts which are measured at fair value, if such disclosures are not already specified elsewhere in GAAP. The new measurement and disclosure requirements of SFAS No. 157 are effective for us in the first quarter 2008. The Company has not yet determined what impact, if any, this statement will have on its financial position or results of operations.

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 2006, 2005, and 2004 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, 2006, 2005, and 2004:

	2006			2005			
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount	
Basic EPS:							
Net Income and Share Amounts	$161,565,340	29,265,366	$5.52	$115,778,456	8,496,275	$4.06	$
Dilutive Securities:							
Restricted Stock	--	168,759		--	61,516		
Stock Options	--	581,891		--	736,937		
Diluted EPS:							
Net Income and Assumed Share Conversions	$161,565,340	30,016,016	$5.38	$115,778,456	29,294,728	$3.95	$

Options to purchase approximately 1.5 million shares at an average exercise price of $24.59 were outstanding at December 31, 2006, while options to purchase 2.1 million shares at an average exercise price of $21.28 were outstanding at December 31, 2005, and options to purchase 3.0 million shares at an average exercise price of $18.51 were outstanding at December 31, 2004. Approximately 1.0 million, 0.1 million, and 1.1 million options to purchase shares were not included in the computation of Diluted EPS for the years ended December 31, 2006, 2005, and 2004, respectively, because these options were antidilutive, in that the sum of the option price, unrecognized compensation expense and excess tax benefits recognized as proceeds in the treasury stock method was greater than the average closing market price for the common shares during those periods. Employee restricted stock grants of 334,425 shares, 6,990 shares and 70,900 shares, were not included in the computation of Diluted EPS for the year ended December 31, 2006, 2005, and 2004, respectively, because these restricted stock grants were antidilutive in that the sum of the unrecognized compensation expense and excess tax benefits recognized as proceeds under 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.

3. Provision for Income Taxes

	Year Ended December 31, (in thousands)		
	2006	2005	2004
United States	$ 247,645	$ 155,863	$ 86,001
Foreign	14,641	22,577	15,439
Total	$ 262,286	$ 178,440	$ 101,440

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

	Year Ended December 31, (in thousands)		
	2006	2005	2004
Current - Domestic	$ 2,860	$ 644	$ 469
Deferred - Domestic	94,375	57,605	31,138
- Foreign	3,486	4,412	1,382
Total Deferred	97,861	62,017	32,520
Total	$ 100,721	$ 62,661	$ 32,989

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

(in thousands)	2006	2005	
Income taxes computed at U.S. statutory rate (35%)	$ 91,800	$ 62,454	$
State tax provisions, net of federal benefits	3,921	2,145	
Effect of foreign operations	(293)	(452)	
Currency exchange impact on foreign tax calculation	(1,346)	(2,769)	
Cumulative impact of adjustments to net state income tax rate	1,547	1,008	
Valuation allowance	3,200	---	
Other, net	1,892	275	
Provision for income taxes	$ 100,721	$ 62,661	$
Effective rate	38.4%	35.1%	

The primary upward adjustment in the effective tax rate above the U.S. statutory rate is the provision for state income taxes (computed net of the offsetting federal benefit), which were $3.9, million, $2.1 million and $1.1 million for 2006, 2005, and 2004, respectively. In 2006 the Company recorded a valuation allowance of $3.2 million discussed further below. Additionally, the Company recorded adjustments to the cumulative state deferred tax liability in the amounts of $1.5 million, $1.0 million, and $0.9 million for 2006, 2005, and 2004, respectively.

Favorable adjustments are primarily attributable to currency exchange impact on foreign operations. 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 In aggregate, the Company recognized foreign exchange benefits to tax expense in the amounts of $1.3 million, $2.8 million, and $2.5 million for 2006, 2005, and 2004, respectively.

The New Zealand statutory rate is 33%, which resulted in differences of $0.3 million, $0.5 million, and $0.3 million for 2006, 2005, and 2004 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, 2006, the undistributed earnings of foreign subsidiaries are approximately $58.5 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, 2006 and 2005 were as follows (in thousands):

	2006	
Current deferred tax assets:		
Carryover items net of valuation allowance (Domestic)	$ 2,383	$
Non-Current deferred tax assets:		
Alternative minimum tax credits (Domestic)	$ (2,202)	$
Carryover items (Domestic)	(2,648)	(
Acquired deferred tax asset (Foreign)	(1,204)	
Carryover Items (Foreign)	(55,197)	(
Unrealized stock compensation	(2,680)	
Other (Domestic)	(325)	
Total deferred tax assets	$ (64,256)	$ (
Non-Current deferred tax liabilities:		
Domestic oil and gas exploration and development costs	$ 224,580	$ 1

Foreign oil and gas exploration and development costs	63,254	
Other (Domestic)	1,389	
Total deferred tax liabilities	$ 289,223	$ 2
Net Non-Current deferred tax liabilities	$ 224,967	$ 1

The total change in the net non-current deferred liability from 2005 to 2006 was $95.7 million. Increases in the liability were attributable to deferred tax expense of $97.9 million, reclassification of a carryover item to current assets of $2.4 million and $0.2 million for other adjustments. Reductions were made to the net liability for the tax benefit of stock compensation deductions of $4.8 million, which are recorded as additions to paid-in-capital.

The primary non-current deferred tax asset is $55.2 million for foreign carryover items. This is attributable to cumulative New Zealand net operating losses of $167.3 million. New Zealand tax net operating losses do not expire.

Other non-current deferred tax assets include $2.7 million for unrealized stock compensation, $2.6 million for State of Louisiana net operating loss carryovers, $2.2 million for U.S. Federal alternative minimum tax credits, and $1.5 million for other items. The unrealized stock compensation is attributable to stock compensation expenses accrued for employee stock options and restricted stock that is not realized for income tax purposes until exercise (for stock options) or vesting (for restricted stock). The actual tax deduction realized may be significantly different than the accrued amounts depending on the market value of the stock on the date of exercise or vesting. The Louisiana net operating loss carryforwards are scheduled to expire between 2013 and 2019. The alternative minimum tax credits carryforward indefinitely. These credits are available to reduce future regular tax liability to the extent they exceed the alternative minimum tax otherwise due.

The Company has not recorded any valuation allowance against any of the non-current deferred tax assets as management estimates that it is more likely than not that these assets will be fully utilized in future periods before any applicable expiration dates. 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.

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The current deferred tax asset of $2.4 million is for capital loss carryforward assets of $6.1 million, offset by a valuation allowance of $3.7 million (an increase of $3.2 million in 2006). The increase in the valuation allowance is due to changes in the Company's property disposition plans. Management expects to realize the net tax asset from a property disposition planned for 2007.

4. Long-Term Debt

Our long-term debt as of December 31, 2006 and 2005, is as follows:

	2006	2005
Bank Borrowings	$ 31,400,000	$ ---
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	$ 381,400,000	$ 350,000,000

Bank Borrowings. At December 31, 2006, we had borrowings of $31.4 million under our $500.0 million credit facility with a syndicate of ten banks that has a borrowing base of $250.0 million and expires in October 2011. At December 31, 2005, we had no borrowings under our credit facility. The interest rate is either (a) the lead bank's prime rate (8.25% at December 31, 2006) 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 October 2006, we increased, renewed and extended this credit facility, increasing the facility to $500 million from $400 million, increasing the commitment amount under the borrowing base to $250 million from $150 million, and extending its expiration to October 3, 2011 from October 1, 2008. The other terms of the credit facility 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 $0.6 million of debt issuance costs related to the extension of this facility in 2006 and $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 $15.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $50.0 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 natural 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, 2006, and the commitment amount was increased to $250.0 million effective October 2, 2006. The next scheduled borrowing base review is in May 2007.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.5 million in 2006, $1.0 million in 2005, and $1.5 million in 2004. The amount of commitment fees included in interest expense, net was $0.6 million in 2006, and $0.5 million in both 2005 and 2004.

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.

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 both 2006 and 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. 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 for each of the years 2006, 2005, and 2004.

The maturities on our long-term debt are $0 for 2007, 2008, 2009 and 2010, $181.4 million for 2011, and $200 million thereafter.

We have capitalized interest on our unproved properties in the amount of $9.2 million, $7.2 million, and $6.5 million, in 2006, 2005, and 2004, respectively.

5. Commitments and Contingencies

Total rental and lease expenses which were included in "General and administrative, net" on our accompanying consolidated statements of income were $3.2 million in 2006, $3.0 million in 2005, and $2.4 million in 2004. Rental and lease expenses which were included in "Lease operating cost" on our accompanying consolidated statements of income were $3.6 million in 2006, $1.9 million in 2005, and $2.2 million in 2004. Our remaining minimum annual obligations under non-cancelable operating lease commitments are $5.3 million for both 2007 and 2008, $3.3 million for both 2009 and 2010, $3.2 million for 2011, and $10.1 million thereafter or $30.6 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 which is a ten year lease and expires in 2015.

In the ordinary course of business, we have entered into agreements with drilling contractors for such services and tubing and pipe inventory commitments. The remaining commitments at December 31, 2006 for these services and materials totaled $28.9 million for 2007.

Through December 2006, we were the managing general partner of two private limited partnerships. Because we served as the general partner of these entities, under state partnership law we were contingently liable for the liabilities of these partnerships. These liabilities are not material for any of the periods presented in relation to the partnerships' respective assets. As of December 31, 2006, these partnerships were dissolved.

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 natural 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, other than stock option reload 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 various terms ranging from three years to five years, stock options become exercisable in various terms ranging from one year to five years. 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, which began in 1993, provides eligible employees the opportunity to acquire shares of Swift Energy common stock at a discount through payroll deductions. Through May 31, 2006, the prior plan year was from June 1 to the following May 31. A transition period from June 1 to

December 31 was used during the second half of 2006 and a new plan year, from January 1 to December 31, began being used in 2007. 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 through the plan year, for plan years ending on or before May 31, 2006). Under this plan for the last three years, we have issued 22,425 shares at a price range of $29.84 to $32.80 in 2006, 32,495 shares at a price range of $15.56 to $18.12 in 2005, and 50,418 shares at a price range of $9.98 to $10.83 in 2004. In January 2007, we issued 17,678 shares at a price of $35.00 related to the transition period ended December 31, 2006. As of December 31, 2006, 84,366 shares remained available for issuance under this plan.

As a result of adopting SFAS No. 123R on January 1, 2006, our income before taxes, net income and basic and diluted earnings per share for the year ended December 31, 2006, were $3.4 million, $2.8 million, $0.09, and $0.09 lower, respectively. Upon adoption of SFAS 123R, we recorded an immaterial cumulative effect of a change in accounting principle as a result of our change in policy from recognizing forfeitures as they occur to one recognizing expense based on our expectation of the amount of awards that will vest over the requisite service period for our restricted stock awards. This amount was recorded in "General and Administrative, net" in the accompanying consolidated statements of income.

We receive a tax deduction for certain stock option exercises during the period the options are exercised, generally for the excess of the price at which the stock is sold over the exercise price of the options. In addition, we receive an additional tax deduction when restricted stock vests at a higher value than the value used to recognize compensation expense at the date of grant. Prior to adoption of SFAS No. 123R, we reported all tax benefits resulting from the award of equity instruments as operating cash flows in our consolidated statements of cash flows. In accordance with SFAS No. 123R, we are required to report excess tax benefits from the award of equity instruments as financing cash flows, these benefits totaled $3.3 million for the year ended December 31, 2006, respectively.

Net cash proceeds from the exercise of stock options were $11.8 million for the year ended December 31, 2006. The actual income tax benefit realized from stock option exercises was $4.8 million for the same period.

Stock compensation expense for both stock options and restricted stock issued to both employees and non-employees is recorded in "General and Administrative, net" in the accompanying consolidated statements of income, and was $6.3 million, $1.5 million, and less than $0.1 million for the years ended December 31, 2006, 2005, and 2004 respectively. We also capitalized $3.4 million, $1.0 million, and $0.1 million of stock compensation in 2006, 2005, and 2004, respectively.

Our shares available for future grant under our stock compensation plans were 959,063 at December 31, 2006. Each stock option granted reduces the aforementioned total by one share, while each restricted stock grant reduces the shares available for future grant by 1.44 shares.

Stock Options. We use the Black-Scholes-Merton option pricing model to estimate the fair value of stock option awards with the following weighted-average assumptions for the indicated periods.

	Years Ended December 31,	
	2006	2005
Dividend yield	0%	0%
Expected volatility	39.3%	41.6%
Risk-free interest rate	4.8%	3.8%
Expected life of options (in years)	4.8	3.9
Weighted-average grant-date fair value	$ 18.03	$ 12.84

The expected term has been calculated using the Securities and Exchange Commission Staff's shortcut approach from Staff Accounting Bulletin No. 107. We have analyzed historical volatility and based on an analysis of all relevant factors use a three-year period to estimate expected volatility of our stock option grants.

At December 31, 2006, $3.6 million of unrecognized compensation cost related to stock options is expected to be recognized over a weighted-average period of 1.5 years.

The following table represents stock option activity for the years ended December 31, 2006, 2005 and 2004:

	2006		2005	
	Shares	Wtd. Avg. Exer. Shares	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	2,118,179	$ 21.28	2,998,668	$ 18.51
Options granted	234,110	$ 45.73	176,262	$ 35.17
Options canceled	(51,739)	$ 22.25	(45,142)	$ 18.94
Options exercised(1)	(751,410)	$ 22.02	(1,011,609)	$ 9.78
Options outstanding, end of period	1,549,140	$ 24.59	2,118,179	$ 21.28
Options exercisable, end of period	884,876	$ 22.60	1,085,509	$ 20.98

The aggregate intrinsic value and weighted average remaining contract life of options outstanding and exercisable at December 31, 2006 was $31.9 million and 5.5 years and $19.8 million and 4.5 years, respectively. The total intrinsic value of options exercised during the year ended December 31, 2006 was $18.4 million.

The following table summarizes information about stock options outstanding at December 31, 2006:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/06	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable At 12/31/06	Wtd. Avg. Exercise Price
$8.00 to $21.99	747,779	5.4	$ 13.56	452,555	$ 13.40
$22.00 to $37.99	513,566	5.3	$ 28.73	374,736	$ 30.09
$38.00 to $51.84	287,795	6.2	$ 45.84	57,585	$ 46.21
$8.00 to $51.84	1,549,140	5.5	$ 24.59	884,876	$ 22.60

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 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. In 2006, 2005 and 2004 respectively, 98,581, 170,762 and 81,716 mature shares were delivered in "stock swap" transactions, which resulted in the issuance of an equal number of reload option grants.

Restricted Stock. In 2006, 2005 and 2004, the Company issued 324,640, 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. The fair value of these shares when issued in 2006, 2005 and 2004 was approximately $43, $38 and $25 per share.

The compensation expense for these awards was determined based on the market price of our stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of December 31, 2006, we have unrecognized compensation expense of approximately $13.9 million associated with

these awards which are expected to be recognized over a weighted-average period of 2.2 years. The total fair value of shares vested during the year ended December 31, 2006 was $1.6 million.

The following is a summary of our restricted stock issued to employees and directors under these plans as of December 31, 2006, 2005, and 2004:

	2006		2005	
	Shares	Wtd. Avg. Grant Price	Shares	Wtd. Avg. Grant Price
Restricted shares outstanding, beginning of period	236,950	$ 34.79	100,900	$ 23.92
Restricted shares granted	324,640	$ 43.21	158,500	$ 38.31
Restricted shares canceled	(22,630)	$ 38.01	(7,450)	$ 39.03
Restricted shares vested	(35,776)	$ 24.57	(15,000)	$ ---
Restricted shares outstanding, end of period	503,184	$ 40.04	236,950	$ 34.79

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, 2006, 2005, and 2004, all of the ESOP compensation was earned. Our contribution to the ESOP plan totaled $0.4 million for the year ended December 31, 2006, and $0.2 million for the years ended December 31, 2005 and 2004, 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 8,927, 4,438, and 6,911 shares for the 2006, 2005, and 2004 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 $1.0 million for 2006, $0.8 million for 2005, and $0.7 million for 2004, and are recorded as "General and administrative, net" on the accompanying consolidated statements of income. The contributions in 2006, 2005, and 2004 were made all in common stock. The shares of common stock contributed to the 401(k) savings plan totaled 23,890, 17,920, and 24,513 shares for the 2006, 2005, and 2004 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, 2006, 427,086 shares remain in treasury (net of 500,688 shares used to fund the ESOP, 401(k) contributions and acquisitions) with a total cost of $6.1 million and are included in "Treasury stock held, at cost" on the accompanying consolidated balance sheet.

Shareholder Rights Plan. Our Rights Agreement was initially adopted by the Board of Directors in 1997 for a ten year term. The Board of Directors renewed and extended the Rights Agreement for an additional ten year term from December 21, 2006. Pursuant to the Rights Agreement as amended, for each share of Swift Energy common stock a holder has the right to purchase one one-thousandth of a share of Swift Energy preferred stock for $250 upon the occurance of certain events triggered when a person or entity purchases 15% or more beneficial ownership of Swift Energy's outstanding common stock. The rights are not exercisable by such 15% or more beneficial owner.

7. Related-Party Transactions

We were 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 2006, 2005, and 2004, 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 $0.1 million per year in 2006 and 2005, and $0.2 million in 2004, and are recorded as reductions in "General and administrative, net." As of December 31, 2006, the remaining two partnerships have been dissolved.

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 aunt of the Company's Chairman of the Board and Chief Executive Officer. We paid approximately $0.5 million to Tec-Com for such services pursuant to the terms of the contract between the parties in 2006, and $0.4 million per year in 2005 and 2004. 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, 2006, our gross capitalized oil and gas property costs in New Zealand totaled approximately $349.1 million. Approximately $332.5 million has been included in the "Proved properties" portion of our oil and gas properties, while $16.6 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 $261.3 million at December 31, 2006. Our capital expenditures on oil and gas property in New Zealand were approximately $56.7 million in 2006.

9. Acquisitions and Dispositions

In October 2006, we acquired interests in five South Louisiana fields. The property interests are located in: Bayou Sale, Horseshoe Bayou and Jeanerette fields (all located in St. Mary Parish), High Island field in Cameron Parish and Bayou Penchant field in Terrebonne Parish. We paid approximately $167.9 million in cash for these interests. After taking into account internal acquisition costs of $4.0 million, our total cost was $171.9 million. We allocated $143.1 million of the acquisition price to "Proved Properties," $28.8 million to "Unproved Properties," and recorded a liability for $11.5 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 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 acquisitions closed in the fourth quarter of 2006, these amounts were not material to our full year 2006 results.

In December 2006, we acquired additional interests in our Lake Washington field. We paid approximately $20.0 million in cash for these interests. After taking into account internal acquisition costs of $0.4 million, our total cost was $20.4 million. We allocated $17.9 million of the acquisition price to "Proved Properties," $2.5 million to "Unproved Properties," and recorded a liability for $0.8 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 this acquisition have been included in our accompanying consolidated statements of income from the date of acquisition forward; however, given the acquisition closed in December 2006, these amounts were not material to our full year 2006 results.

In April 2006, we sold our minority interest in the Brookeland natural gas processing plants for approximately $20.3 million in cash. Under the "full-cost" method of accounting for oil and gas property and equipment costs, the proceeds of this sale were applied against our oil and gas properties and equipment balance, and no gain or loss was recognized on this transaction.

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 2006, we acquired additional interests in this field. We paid approximately $4.5 million in cash for these additional interests. After taking into account internal acquisition costs of $0.1 million, our total cost was $4.6 million. We allocated $4.1 million of the acquisition price to "Proved Properties" and $0.5 million to "Unproved Properties" 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 the acquisition closed. However, given the acquisitions closed in November 2005 and December 2006, these amounts were immaterial for both the 2005 and 2006 periods.

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" and $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 the acquisition closed. However, given the acquisition closed 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 other subsidiaries:

Condensed Consolidating Balance Sheets

(in 000's)	December 31, 2006			
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	E
ASSETS				
Current assets	$ ---	$ 75,270	$ 17,303	$
Property and equipment	---	1,239,722	243,590	
Investment in subsidiaries (equity method)	797,917	---	590,720	
Other assets	---	42,519	705	
Total assets	$ 797,917	$ 1,357,511	$ 852,318	$
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities	$ ---	$ 137,016	$ 8,959	$
Long-term liabilities	---	629,775	45,442	
Stockholders' equity	797,917	590,720	797,917	
Total liabilities and stockholders' equity	$ 797,917	$ 1,357,511	$ 852,318	$

(in 000's)	December 31, 2005			
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	E
ASSETS				
Current assets	$ ---	$ 92,788	$ 22,267	$
Property and equipment	---	862,717	216,316	
Investment in subsidiaries (equity method)	607,318	---	410,612	
Other assets	---	31,955	682	
Total assets	$ 607,318	$ 987,460	$ 649,877	$

LIABILITIES AND STOCKHOLDERS' EQUITY

Current liabilities	$ ---	$ 85,472	$ 12,949	$
Long-term liabilities	---	491,376	29,610	
Stockholders' Equity	607,318	410,612	607,318	
Total liabilities and stockholders' equity	$ 607,318	$ 987,460	$ 649,877	$

(in 000's)

	December 31, 2004			
	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations	Swi C
ASSETS				
Current assets	$ 38,713	$ 15,673	$ ---	$
Property and equipment	719,209	204,229	---	
Investment in subsidiaries (equity method)	104,003	---	(104,003)	
Other assets	116,537	2,364	(106,152)	
Total assets	$ 978,462	$ 222,265	$ (210,155)	$
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities	$ 60,160	$ 8,458	$ ---	$
Long-term liabilities	444,130	109,805	(106,152)	
Stockholders' Equity	474,172	104,003	(104,003)	
Total liabilities and stockholders' equity	$ 978,462	$ 222,265	$ (210,155)	$

Condensed Consolidating Statements of Income

(in 000's)

	Year Ended December 31, 200			
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	E

Revenues	$ ---	$ 550,540	$ 64,901
Expenses	---	302,232	50,923
Income (loss) before the following:	---	248,308	13,978
Equity in net earnings of subsidiaries	161,565	---	151,075
Income before income taxes	161,565	248,308	165,052
Income tax provision (benefit)	---	97,234	3,487
Net income	$ 161,565	$ 151,074	$ 161,565

(in 000's) Year Ended December 31, 200

	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries
Revenues	$ ---	$ 354,367	$ 68,893
Expenses	---	198,237	46,583
Income (loss) before the following:	---	156,130	22,309
Equity in net earnings of subsidiaries	115,778	---	97,880
Income before income taxes	115,778	156,130	120,190
Income tax provision (benefit)	---	58,249	4,412
Net income	$ 115,778	$ 97,881	$ 115,778

(in 000's) Year Ended December 31, 2004

	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Elminations
Revenues	$ 256,608	$ 53,817	$ (147)
Expenses	171,147	37,838	(147)
Income (loss) before the following:	85,461	15,979	---
Equity in net earnings of subsidiaries	14,733	---	(14,733)
Income before income taxes	100,194	15,979	(14,733)
Income tax provision (benefit)	31,743	1,247	---

Net income	$ 68,451	$ 14,733	$ (14,733)	$ -

Condensed Consolidating Statements of Cash Flow

(in 000's)	Year Ended December 31, 2006			
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Elmin
Cash flow from operations	$ ---	$ 383,241	$ 41,680	$
Cash flow from investing activities	---	(474,781)	(59,881)	
Cash flow from financing activities	---	46,679	11,115	
Net decrease in cash	---	(44,861)	(7,086)	
Cash, beginning of period	---	44,911	8,094	
Cash, end of period	$ ---	$ 50	$ 1,008	$

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

(in 000's)	Year Ended December 3
	Swift Energy Co. (Parent and

	Issuer)	Other Subsidiaries	E
Cash flow from operations	$ 147,114	$ 35,469	$
Cash flow from investing activities	(158,308)	(35,878)	
Cash flow from financing activities	10,357	5,100	
Net increase (decrease) in cash	(837)	4,691	
Cash, beginning of period	1,042	24	
Cash, end of period	$ 205	$ 4,715	$

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:

	2006		
	Domestic	New Zealand	Total
Oil and gas sales	$ 537,512,509	$ 64,038,859	$ 601,551,368
Costs and Expenses:			
Depreciation, depletion, and amortization	(139,244,630)	(30,051,144)	(169,295,774)
Accretion of asset retirement obligation	(884,105)	(150,217)	(1,034,322)
Lease operating cost	(49,948,039)	(12,526,580)	(62,474,619)
Severance and other taxes	(61,234,906)	(4,217,137)	(65,452,043)
Income from oil and gas operations	$ 286,200,829	$ 17,093,781	$ 303,294,610
Price-risk management and other, net			13,889,862
General and administrative, net			(31,316,644)
Interest expense, net			(23,581,663)
Income before Income Taxes			$ 262,286,165

Property and Equipment, net	$1,255,331,575	$ 227,980,590	$ 1,483,312,165
Total Assets	1,349,684,402	235,997,356	1,585,681,758
Capital Expenditures	$ 502,342,254	$ 55,149,258	$ 557,491,512

	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			$ 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

	2004		
	Domestic	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			$ 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

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
December 31, 2006:		
Proved oil and gas properties	$ 2,264,831,638	$ 1,932,336,298
Unproved oil and gas properties	112,136,836	95,569,089
	2,376,968,474	2,027,905,387
Accumulated depreciation, depletion, and amortization	(915,397,437)	(808,708,770
Net capitalized costs	$ 1,461,571,037	$ 1,219,196,617
December 31, 2005:		
Proved oil and gas properties	$ 1,731,866,298	$ 1,468,981,981
Unproved oil and gas properties	87,553,220	58,196,531
	1,819,419,518	1,527,178,512
Accumulated depreciation, depletion, and amortization	(748,327,443)	(671,117,089
Net capitalized costs	$ 1,071,092,075	$ 856,061,423

Of the $95.6 million of domestic Unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2006, excluded from the amortizable base, $68.3 million was incurred in 2006, $13.3 million was incurred in 2005, $8.9 million was incurred in 2004, and $5.1 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 $16.6 million of New Zealand Unproved property costs at December 31, 2006, excluded from the amortizable base, $8.0 million was incurred in 2006, $2.1 million was incurred in 2005, $1.7 million was incurred in 2004, and $4.8 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, 2006, 2005, and 2004.

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

	Year Ended December 31,	
	Total	Domestic
Acquisition of proved and unproved properties	$ 212,499,280	$ 212,499,280
Lease acquisitions and prospect costs(1)	79,183,368	68,594,051
Exploration	29,285,958	13,224,894
Development (2)	261,142,220	231,085,290
Total acquisition, exploration, and development (3),(4)	$ 582,110,826	$ 525,403,515

	Year Ended December 31	
	Total	Domestic
Acquisition of proved and unproved properties	$ 31,429,343	$ 31,429,343
Lease acquisitions and prospect costs(1)	41,397,277	34,502,163
Exploration	52,350,339	38,424,995
Development (2)	141,081,231	111,057,945
Total acquisition, exploration, and development (3),(4)	$ 266,258,190	$ 215,414,446

	Year Ended December 31	
	Total	Domestic
Acquisition of proved and unproved properties	$ 31,771,094	$ 31,771,094
Lease acquisitions and prospect costs(1)	34,545,393	27,713,059
Exploration	17,430,265	16,714,982

Development (2)	108,259,091	79,338,697
Total acquisition, exploration, and development (3),(4)	$ 192,005,843	$ 155,537,832

(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 2006, 2005, and 2004 were $70.5 million, $30.4 million, and $17.8 million, respectively. Domestic costs for seismic data acquisition, included above, were $23.1 million, 4.2 million, and $1.0 million in 2006, 2005 and 2004, respectively. New Zealand costs for seismic data acquisition, included above were $3.8 million in 2006.

(2)Facility construction costs and capital costs have been included in development costs, and totaled $16.5 million, $26.9 million, and $12.6 million for the years ended December 31, 2006, 2005 and 2004.

(3)Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $28.3 million, $18.8 million, and $13.1 million in 2006, 2005, and 2004, respectively. In addition, total includes $9.2 million, $7.2 million, and $6.5 million in 2006, 2005, and 2004, respectively, of capitalized interest on unproved properties.

(4)Asset retirement obligations incurred have been included in exploration, development and acquisition costs as applicable for the years ended December 31, 2006, 2005, and 2004.

Results of Operations.

	Year Ended December 31, 2006		
	Total	Domestic	New Zea
Oil and gas sales	$ 601,551,368	$ 537,512,509	$ 64,
Lease operating cost	(62,474,619)	(49,948,039)	(12,
Severance and other taxes	(65,452,043)	(61,234,906)	(4,
Depreciation, depletion, and amortization	(166,518,190)	(136,826,013)	(29,
Accretion of asset retirement obligation	(1,034,322)	(884,105)	(
	306,072,194	288,619,446	17,
Provision for income taxes	117,531,722	110,829,867	6,
Results of producing activities	$ 188,540,472	$ 177,789,579	$ 10,
Amortization per physical unit of production (equivalent Mcf of gas)	$ 2.37	$ 2.41	$

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

	Year Ended December 31, 2004		
	Total	Domestic	New Zea
Oil and gas sales	$ 311,285,172	$ 258,663,936	$ 52,
Lease operating cost	(41,214,256)	(30,191,889)	(11,
Severance and other taxes	(30,401,293)	(26,713,592)	(3,
Depreciation, depletion and amortization	(80,504,043)	(61,478,364)	(19,
Accretion of asset retirement obligation	(673,654)	(505,174)	(
	158,491,926	139,774,917	18,7
Provision for income taxes	53,093,022	51,576,944	1,5
Results of producing activities	$ 105,398,904	$ 88,197,973	$ 17,2
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.38	$ 1.46	$

These results of operations do not include the gains from our hedging activities of $4.0 million in 2006, and losses from our hedging activities of $1.1 million and $1.3 million for 2005 and 2004, respectively. Our lease operating costs per Mcfe produced were $0.89 in 2006, $0.79 in 2005, and $0.71 in 2004.

The accretion of asset retirement obligation has been included in the 2006, 2005 and 2004 periods.

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

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 us. Gruy's report dated January 23, 2007, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 2006, 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	
	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)	Natural Gas (Mcf)	Oil, NG and Condens (Bbls)
Proved reserves as of December 31, 2003	335,804,862	80,759,903	242,321,275	67,015
Revisions of previous estimates(1)	(3,306,705)	(1,117,715)	(1,619,531)	695
Purchases of minerals in place	9,808,953	5,602,508	9,808,953	5,602
Sales of minerals in place	(2,524,760)	(44,803)	(2,524,760)	(44
Extensions, discoveries, and other additions	2,205,670	830,111	2,205,670	830
Production	(23,741,726)	(5,762,796)	(12,299,772)	(4,959
Proved reserves as of December 31, 2004	318,246,294	80,267,208	237,891,835	69,139
Revisions of previous estimates(1)	(21,461,605)	(2,199,673)	(13,751,124)	(1,023
Purchases of minerals in place	9,336,088	3,262,761	9,336,088	3,262
Sales of minerals in place	(3,737,714)	(100,121)	(3,737,714)	(100
Extensions, discoveries, and other additions	8,699,329	3,819,595	7,275,207	3,722
Production	(23,609,242)	(5,996,714)	(11,739,485)	(5,217
Proved reserves as of December 31, 2005	287,473,150	79,053,056	225,274,807	69,783
Revisions of previous estimates(1)	(33,631,025)	3,127,635	(34,542,219)	3,135
Purchases of minerals in place	60,187,095	2,922,553	60,187,095	2,922
Sales of minerals in place	(6,122,283)	(708,691)	(6,122,283)	(708
Extensions, discoveries, and other additions	39,012,428	5,627,297	38,466,980	5,512
Production	(22,787,948)	(7,902,766)	(13,603,589)	(7,181
Proved reserves as of December 31, 2006	324,131,417	82,119,084	269,660,791	73,464
Proved developed reserves: (2)				
December 31, 2003	210,119,927	45,525,366	138,173,341	38,767
December 31, 2004	193,310,761	42,037,852	140,549,052	36,628
December 31, 2005	152,001,133	37,989,821	125,367,690	35,298
December 31, 2006	151,276,834	34,956,469	133,815,108	33,345

(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, 2006, were based upon prices in effect at year-end. Our hedges at year-end 2006 consisted of natural gas price floors with strike prices higher than the period end price and thus would not materially affect prices used in these calculations. The weighted average of 2006 year-end prices for total, domestic, and New Zealand were $5.46, $5.84, and $3.59 per Mcf of natural gas, $60.41, $60.07, and $63.51 per barrel of oil, and $30.93, $31.54 and $26.84 per barrel of NGL, respectively. This compares to $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 as of December 31, 2005, for total, domestic, and New Zealand, respectively. The weighted average of 2004 year-end prices for total, domestic, and New Zealand were $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, respectively.

(2)At December 31, 2006, 44% of our reserves were proved developed, compared to 50% at December 31, 2005, 56% at December 31, 2004, and 59% at December 31, 2003.

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

	Year Ended December 31,	
	Total	Domestic
Future gross revenues	$ 6,341,394,321	$ 5,659,084,913
Future production costs	(1,393,634,094)	(1,167,117,123)
Future development costs	(935,003,617)	(886,842,793)
Future net cash flows before income taxes	4,012,756,610	3,605,124,997
Future income taxes	(1,187,858,603)	(1,137,617,295)
Future net cash flows after income taxes	2,824,898,007	2,467,507,702
Discount at 10% per annum	(956,238,277)	(835,593,066)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,868,659,730	$ 1,631,914,636

	Year Ended December 31,	
	Total	Domestic
Future gross revenues	$ 6,917,103,123	$ 6,194,560,214
Future production costs	(1,334,822,738)	(1,122,637,935)
Future development costs	(710,343,331)	(667,526,650)

Future net cash flows before income taxes	4,871,937,054	4,404,395,629
Future income taxes	(1,538,799,956)	(1,461,577,946)
Future net cash flows after income taxes	3,333,137,098	2,942,817,683
Discount at 10% per annum	(1,173,767,635)	(1,048,193,951)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 2,159,369,463	$ 1,894,623,732

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

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.

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 2006 consisted mainly of natural gas price floors with strike prices higher than the period end price and 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,		
	2006	2005	
Beginning balance	$ 2,159,369,463	$ 1,464,945,495	$ 1
Revisions to reserves proved in prior years--			
Net changes in prices, and production costs	(658,283,413)	1,232,876,998	
Net changes in future development costs	(166,890,534)	(173,219,347)	
Net changes due to revisions in quantity estimates	(60,713,716)	(138,969,442)	
Accretion of discount	314,344,631	199,799,374	
Other	(98,478,730)	17,191,849	
Total revisions	(670,021,762)	1,137,679,432	
New field discoveries and extensions, net of future production and development costs	212,629,383	152,461,162	
Purchases of minerals in place	289,338,576	99,129,117	
Sales of minerals in place	(20,378,583)	(10,164,069)	
Sales of oil and gas produced, net of production costs	(473,624,706)	(334,267,899)	
Previously estimated development costs incurred	187,133,510	100,614,837	
Net change in income taxes	184,213,849	(451,028,612)	
Net change in standardized measure of discounted future net cash flows	(290,709,733)	694,423,968	
Ending balance	$ 1,868,659,730	$ 2,159,369,463	$ 1

Selected Quarterly Financial Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2006 and 2005:

	Revenues	Income Before Income Taxes	Net Income	Basic EPS Net Income	Diluted EPS Net Income
2006:					
First	$ 136,168,931	$ 57,774,996	$ 37,314,506	$ 1.28	$ 1.24
Second	147,177,246	60,189,700	38,168,448	1.31	1.27
Third	173,458,852	82,209,164	50,811,567	1.74	1.68
Fourth	158,636,201	62,112,305	35,270,819	1.19	1.16
Total	$ 615,441,230	$ 262,286,165	$ 161,565,340	$ 5.52	$ 5.38
2005:					
First	$ 95,620,684	$ 39,758,619	$ 25,689,152	$ 0.91	$ 0.89
Second	104,299,925	41,778,041	27,881,658	0.98	0.96
Third	100,853,505	42,901,655	27,506,899	0.96	0.92
Fourth	122,452,375	54,001,236	34,700,747	1.20	1.16
Total	$ 423,226,489	$ 178,439,551	$ 115,778,456	$ 4.06	$ 3.95

There were no extraordinary items in 2006 or 2005.

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.

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

None.

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 this 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, 2006 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, Executive Officers and Corporate Governance

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 8, 2007, 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 8, 2007, 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 8, 2007, annual shareholders' meeting is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

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 8, 2007, 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 8, 2007, annual shareholders' meeting is incorporated by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

o 1. The following consolidated financial statements of Swift Energy Company together with the report thereon of Ernst & Young LLP dated February 27, 2007, and the data contained therein are included in Item 8 hereof:

Management's Report on Intern