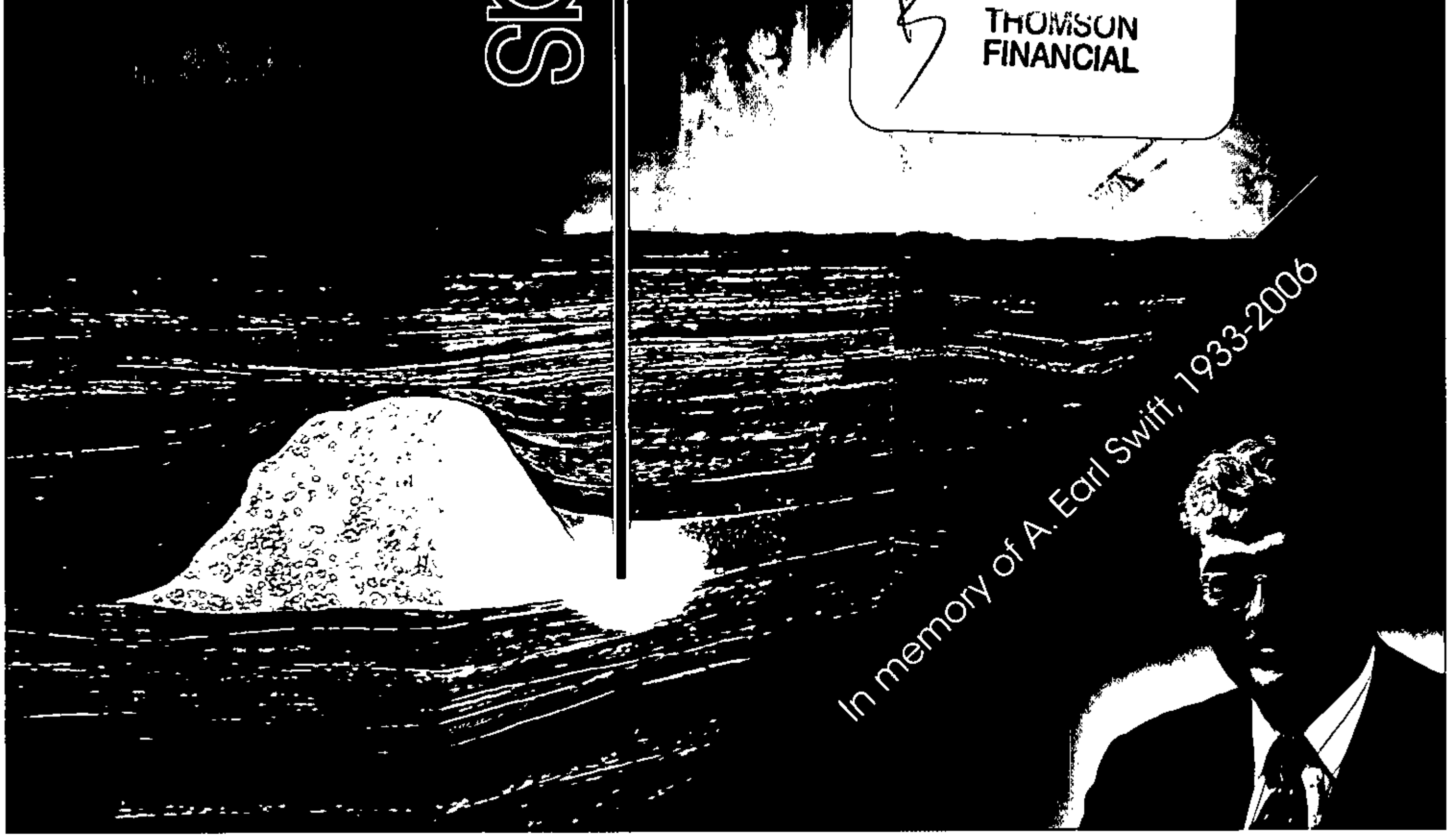
SWIFT ENERGY COMPANY
2006 ANNUAL REPORT

bright ideas



In memory of A. Earl Swift, 1933-2006

Highlights

	2006	2005	Percent Change
Revenues	$615,441,230	$423,226,489	45%
Costs & Expenses	$353,155,065	$244,786,938	44%
Net Income	$161,565,340	$115,778,456	40%
Earnings per Share–Basic	$5.52	$4.06	36%
Earnings per Share–Diluted	$5.38	$3.95	36%
Total Assets	$1,585,681,758	$1,204,412,622	32%
Working Capital	$(53,402,247)	$16,634,121	NA
Current Ratio	0.63	1.17	(46%)
Long-Term Debt	$381,400,000	$350,000,000	9%
Stockholders' Equity	$797,916,972	$607,318,167	31%
Long-Term Debt to Equity Ratio	0.48	0.58	(17%)
Return on Assets (Net Income / Average Assets)	11.6%	10.5%	10%
Return on Stockholders' Equity (Net Income / Average Equity)	23.0%	21.4%	7%
Net Cash Provided by Operating Activities	$424,921,046	$285,333,484	49%
Total Production (Mcfe)	70,204,544	59,589,526	18%
Natural Gas Production (Mcf)	22,787,948	23,609,242	(3%)
Oil & Condensate Production (Bbls)	7,189,762	5,158,962	39%
Natural Gas Liquids Production (Bbls)	713,004	837,752	(15%)
Average Composite Prices Received ($/Mcfe)	$8.57	$7.11	21%
Average Natural Gas Prices Received ($/Mcf)	$5.05	$5.23	(3%)
Average Oil & Condensate Prices Received ($/Bbl)	$64.47	$53.63	20%
Average Natural Gas Liquids Prices Received ($/Bbl)	$32.15	$28.04	15%
Total Proved Reserves (Mcfe)	816,845,916	761,791,482	7%
Proved Natural Gas Reserves (Mcf)	324,131,417	287,473,150	13%
Proved Oil & Condensate Reserves (Bbls)	68,922,412	64,946,534	6%
Proved Natural Gas Liquids Reserves (Bbls)	13,196,671	14,106,522	(6%)
Weighted Average Shares Outstanding	29,265,366	28,496,275	3%
Year-End Shares Outstanding	29,742,918	29,009,530	3%
Number of Shareholders of Record	252	258	(2%)
Number of Shareholders in Street Name (estimated)	23,300	23,450	(1%)
Market Price of Common Stock at Year-End	$44.81	$45.07	(1%)
Price-Earnings Ratio (Year-End Stock Price / EPS–Basic)	8.1	11.1	(27%)
Number of Employees	345	311	11%

See page 36 regarding the forward-looking statements in this report.
See page 77 for a glossary of abbreviations and terms.

FOR ADDITIONAL INFORMATION, PLEASE CONTACT:

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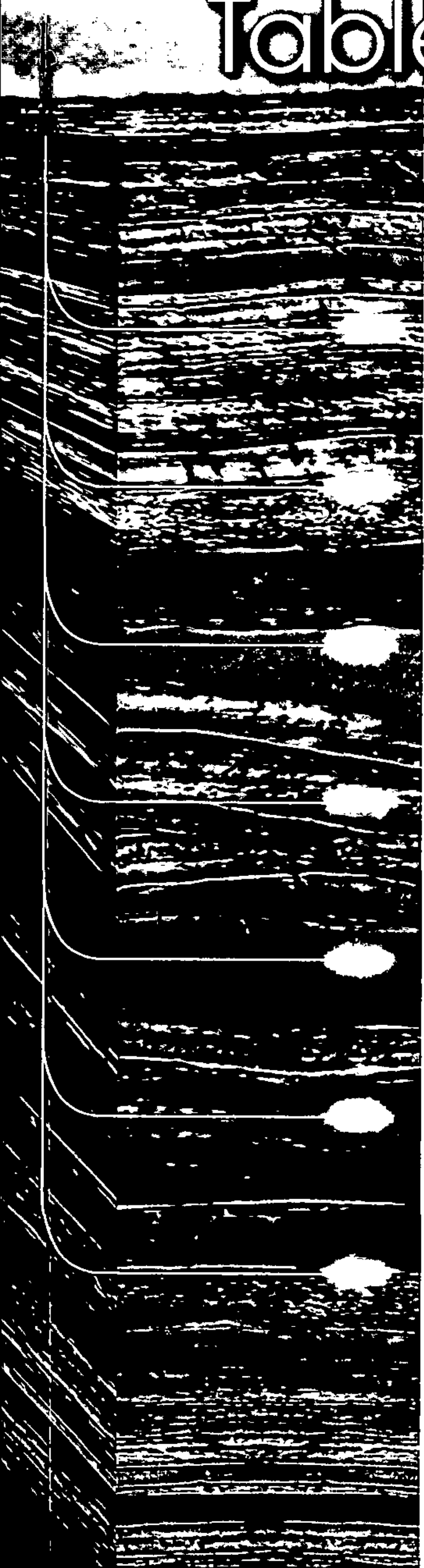

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INTERNET ACCESS

Investor information about Swift Energy Company is available on the Internet at www.swiftenergy.com. The information includes press releases, Swift's code of ethics, and company hedging positions. It also includes Swift's annual reports on Form 10-K, quarterly reports on Form 10-Q, and links to current reports on Form 4 and Form 8-K, all available free of charge and updated as soon as practicable after the company's filing of these reports with the U.S. Securities and Exchange Commission. Visitors to swiftenergy.com can register to receive periodic e-mail updates concerning new information available at the web site.

Company Profile

Highlighting Our Success

Swift Energy Company is an independent oil and natural gas company engaged in the development, exploration, acquisition, and operation of oil and gas properties. In the United States, we focus on the onshore and inland water areas of the Louisiana and Texas Gulf Coast, and in New Zealand on the North Island's Taranaki Basin. Founded in 1979, our company has its principal headquarters in Houston, Texas.

MISSION AND GOALS As a natural resource company, we are committed to achieving efficient, sustained growth in the volume and value of our proved oil and gas reserves, while simultaneously maintaining high standards for ethical conduct, the protection of health and safety, and the preservation of environmental quality. In all our activities, we focus on optimizing stakeholder value by building a balanced portfolio of oil and gas properties with diversified production profiles and an assortment of growth opportunities covering a range of risks and potential rewards.

Over the last five years, we have achieved an average compounded growth rate in proved oil and gas reserves of approximately 5% per year, and in 2006, we increased our year-end proved reserves by 7% from the previous year-end to almost 817 billion cubic feet equivalent (Bcfe). Because our company has been able to build a high-quality portfolio of oil and gas reserves during a period of tight supplies, we have achieved five-year compounded growth rates of approximately 9% per year in production, 27% per year in oil and gas sales, and 25% per year in cash flows from operating activities.

Going forward, we have assembled a database of three-dimensional seismic data covering 4,000 square miles in South Louisiana, creating a strong foundation for sustained growth. Over the next five years, our primary strategic goals are to increase our proved oil and gas reserves at an average rate of 5% to 10% per year and our production at an average rate of 7% to 12% per year.

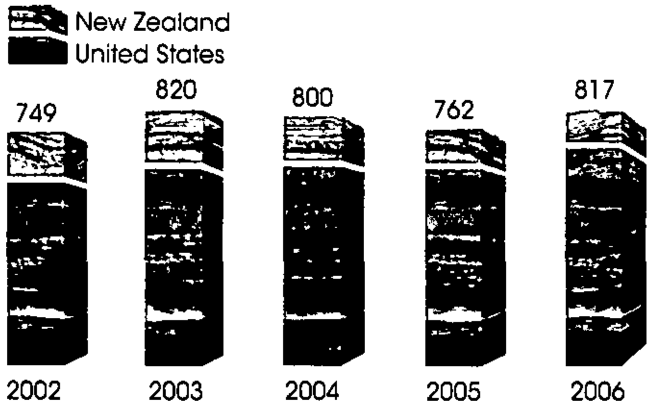
BUSINESS STRATEGY Our mission of reserves growth is primarily accomplished through a mix of exploratory and development drilling and producing property acquisitions. The specific mix of drilling and acquisitions is continually adjusted in response to changing industry conditions and strategic opportunities.

U.S. operations are generally focused in three regions—South Louisiana, South Texas, and Toledo Bend, a region spanning the Texas-Louisiana border. Within each region are one or more key properties, or anchor assets, that give us a strong base for developing the surrounding area. These include the Lake Washington, Bay de Chene, and Cote Blanche Island properties in South Louisiana, the AWP Olmos property in South Texas, and the Brookeland and Masters Creek properties in Toledo Bend. A fourth region of operation is in the Taranaki Basin of New

Zealand and includes the Rimu/Kauri and TAWN properties. These anchor areas not only provide us with most of our production but also with the opportunity for reserves additions through continued development and exploratory drilling. In 2006, we focused the majority of our drilling activities in South Louisiana, and it will again be our most active region in 2007.

In our acquisitions activities, we continually review opportunities to purchase strategic producing properties whose performance can be enhanced through further development and exploratory drilling or through improved operating efficiencies. This

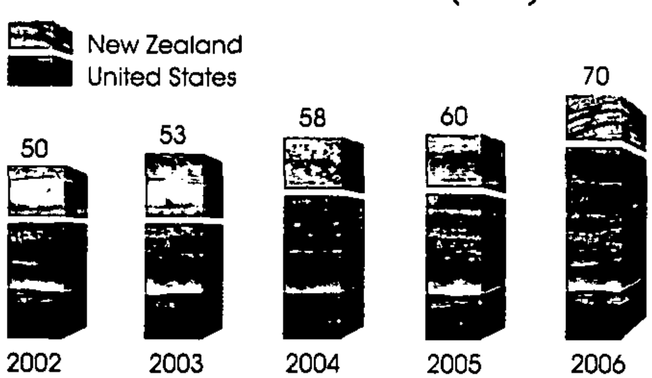
Year-End Proved Oil & Gas Reserves (Bcfe)



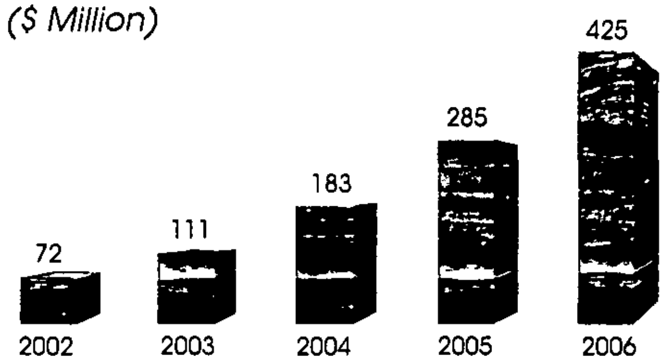
approach led to the purchase of our initial properties in AWP in 1988, Brookeland and Masters Creek in 1998, Lake Washington in 2001, TAWN in 2002, and Bay de Chene and Cote Blanche Island in 2004. In 2005 and 2006, we acquired interests in the South Bearhead Creek Field located in the Toledo Bend Region, and in 2006, we acquired interests in five additional properties in South Louisiana and increased our interests in our Lake Washington property.

INDUSTRY ENVIRONMENT Volatility in the prices of crude oil, natural gas, and natural gas liquids (NGLs) can have a significant impact on revenues and earnings from our operations. In 2006, the average domestic crude oil prices we received

Annual Oil & Gas Production (Bcfe)



Cash Flow Provided by Operating Activities ($ Million)

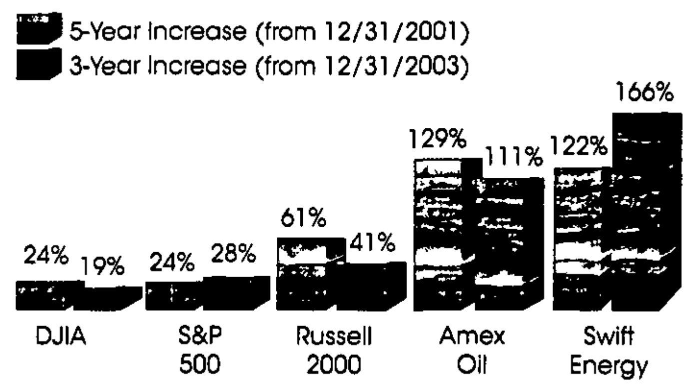


increased 20% to $64.28 per barrel. Average domestic NGL prices increased 14% to $38.70 per barrel, while domestic natural gas prices declined 13% to $6.44 per thousand cubic feet (Mcf).

In New Zealand, we received an average of $67.06 per barrel for our crude oil, an increase of 21% from 2005 levels. Average NGL prices increased 7% to $20.22 per barrel, and natural gas prices declined 3% to $2.99 per Mcf, primarily due to exchange rate variations.

PERFORMANCE COMPARISON Our policy has always been to reinvest cash flows rather than pay

3-Year & 5-Year Cumulative Equity Increases



cash dividends in order to promote long-term growth in the value of our common stock. Although industry cycles can have a substantial impact on year-to-year performance, we have achieved excellent growth in shareholder value in recent years. At the end of 2006, the three-year cumulative appreciation in our year-end stock price totaled 166%, comparing favorably with three-year increases in the Amex Oil Index (111%), the Russell 2000 Index (41%), the S&P 500 Index (28%), and the Dow Jones Industrial Average (19%).

INVESTOR INFORMATION Our common stock has been traded under the symbol "SFY" on the New York Stock Exchange (NYSE) since 1991.

Letter to Stockholders

Radiating Synergy

We are living in a world that is undergoing two simultaneous transformations of global magnitude: one in energy supply and demand and the other in digital communications and information-processing technologies. In the oil and gas industry, these two transformations have converged, leading to a revolution in the way we search for oil and gas. It's an era for new ideas—or, as our report theme suggests, bright ideas—that can help us become more effective in finding and producing oil and gas during a period of increasingly tight energy supplies. In the face of this transition, there is little time to savor past successes. But the future builds on the past, and our past, including our successes in 2006, gives us a solid foundation.

There is no question that 2006 was an outstanding year for us—one in which we achieved all-time highs in production, revenues, and earnings. Our production rose 18%; revenues went up 45%; and diluted earnings per share increased 36%. Our proved reserves also increased 7%. We believe these successes are a testimony to the correctness of our operational strategy and the dedication of our employees.

That said, great successes usually bring with them new challenges, and a major challenge for our domestic industry is to economically add new oil and gas reserves and increase production at a time when domestic oil and gas resources are increasingly difficult to find. We are confident that Swift can meet that challenge. In 2007, our goals are to increase our proved oil and gas reserves by 4% to 6% and our production by 7% to 10%.

We will be working to accomplish these growth goals in an environment of falling U.S. production. Over the last five years, our nation's annual oil production has dropped by 10% and its natural gas production by 5%, even as more and more wells have been drilled. But despite the maturing of our nation's oil and gas resources and the looming peak in world oil production, opportunities for discovering new hydrocarbon pools are still abundant. They are just harder to find in the smaller accumulations and deeper horizons where they reside. Plenty of resources are left in the ground, but the easy-to-exploit resources are generally gone.

As we search for new reserves, we face pressures from rising service costs. After decades of low prices and underinvestment in energy supplies, the world simply does not have the intellectual or physical infrastructure in place to meet rising demands in the industry for skilled workers and equipment. Over the last four years, government statistics show that the number of wells drilled annually is up 87% and total footage drilled is up 102%. In January 2007, demand for seismic crews was up 58% from January 2003. In effect, portions of the service industry have been asked to almost double in size in recent years and despite all that effort, U.S. production continues to fall.

Part of the answer to this challenge is new digital technologies. Some industry observers have proclaimed the coming of the "digital oilfield" or the "digital organization." It is a vision of the future in which digital technologies begin to reshape every aspect of the oil and gas business. At Swift Energy we agree that the digital revolution is indeed creating new opportunities for collaboration and creativity, both within our own organization and between our company and its network of suppliers. The result is new synergies that can reduce our costs and increase our effectiveness in finding and producing oil and gas. Measurement-while-drilling tools have enabled more precise directional and horizontal drilling; improvements in telecommunications have enabled remote monitoring of formation-fracturing stimulations and production; video conferencing has connected remote locations in real time, even on opposite sides of the globe; and digital information systems are improving access to timely financial and operating data.

Nowhere, however, is the impact of digital technologies more important than in the area of seismic imaging. Seismic technologies and computer power have developed hand in hand for over 40 years. When the integrated circuit was first invented in the late 1950s, one of its principal creators was working for an organization that originally began as a geophysical service company. Today, improvements in measuring instruments and computing power are enabling three-dimensional seismic technologies to look deeper into the earth at finer resolutions, allowing us to explore new horizons that have yet to be tapped.

At Swift Energy, we have responded to these capabilities by amassing 4,000 square miles of three-dimensional seismic data from various sources in two South Louisiana areas and merging them to obtain an integrated dataset for each area. The integration of previously distinct datasets generates synergies that improve the quality of all the pre-existing data, allowing us to model the subsurface environment with more accurate images. These seismic data are then integrated again with digitized well-log data, creating even better pictures of subsurface structures. Eventually, the data are further analyzed using a variety of other techniques, some of which not only give us knowledge of subsurface structure but also identify "bright spots" that provide direct indications of the presence of hydrocarbons. The result is a synergistic amalgamation of large amounts of digital data that give us a better picture of under-explored areas where we believe new accumulations of oil and gas resources are likely to be found.

Over the last three years, we have invested $28.3 million in acquiring domestic seismic data and an-

other $3.8 million for similar data in New Zealand. We have also prepared for continued drilling successes by spending another $155.1 million on proved and unproved lease acquisitions and prospect development and $56.0 million on improving our facilities. Of course, some of these expenditures were necessary for our ongoing operations over the last three years, but a significant portion of the costs help lay the groundwork for additional future growth. As a result, our reserves replacement costs in 2006 were higher than we would have liked, about 50% of our average sales price, but we believe those costs will go down as the benefit of our previous investments are realized in subsequent years.

We have clearly felt the impacts of these investments. In 2005, we had two significant exploratory successes based upon our three-dimensional seismic data, our Newport and Bondi wells in Lake Washington. Through the end of last year, we followed those discoveries with seven successful Newport delineation wells (one in 2005 and six in 2006) that have been among the most productive wells drilled in the state waters of Louisiana in the last 50 years. Overall in 2006, we achieved a drilling success rate of 86% in Lake Washington by using our first integrated seismic dataset to determine drilling locations for all our wells, and we expect similar results as we rely on both datasets for drilling in other South Louisiana anchor areas during 2007.

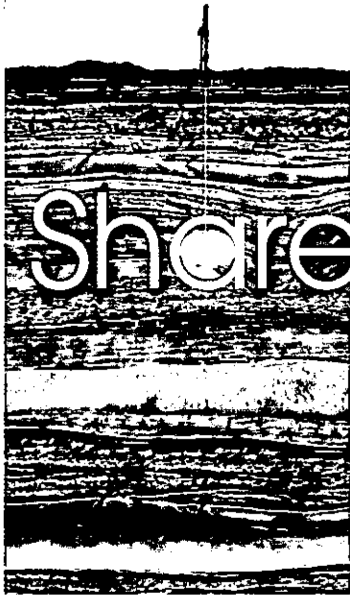
Our seismic-based technology is also enhancing our acquisition activities. In 2006, we made the largest producing property acquisition in our history, the purchase of interests in five primarily onshore South Louisiana fields located in the parishes of St. Mary, Cameron, and Terrebonne. Since we had previously acquired three-dimensional seismic data for these areas and had merged them into our datasets, we were able to identify strategic opportunities associated with the properties prior to their purchase. Equally important, because we already have the seismic data for these fields in place, we will be able to accelerate our exploration and development efforts in the fields and generate new value from the acquisition more quickly than we have for other acquisitions in the past.

Over time, we intend to apply our digital strategy in other regions of operation. In New Zealand, for example, we undertook a 59-square-mile three-dimensional marine seismic survey over our Kaheru prospect in 2006, and we are considering a three-dimensional seismic survey associated with our TAWN property.

All things considered, we are confident of our strategy and pleased with our progress. We have always believed that the best way to adapt to the future is to create it. Over the last three years, we have been creating a bright future for ourselves and our stakeholders by building an inventory of new ideas that combine synergistically with one another to generate new value. We believe that 2006 was an exceptional year for us, not only because we achieved great results, but even more so because we laid the foundation for greater success in the years ahead.

Terry E. Swift
Chairman and Chief Executive Officer,
Swift Energy Company

Terry E. Swift



Shareholder Value

Illuminating Channels for Growth

Over the past three years our shareholders have benefited from appreciation in Swift Energy's stock price.

Since year-end 2003, the price of our common stock has grown at an average rate of 39% per year, closing at $44.81 per share at year-end 2006. Increases in earnings supported this growth, with diluted earnings per share rising at an average rate of 71% per year between 2003 and 2006. Our net income in 2006 was $161.6 million, up more than fivefold from $29.9 million in 2003.

Since our first full year of operations in 1980, we have had a compounded growth rate of 18% per year in proved reserves per share of common stock, with proved reserves totaling 28 Mcfe per share at year-end 2006. Similarly, our per-share production has grown at a compounded rate of 32% per year since our production activities were first initiated in 1981.

For many years we accomplished this growth by using the industry's cycles to our advantage, emphasizing drilling when prices were high and producing property acquisitions when prices were low. In recent years as prices have remained strong, particularly for oil, we have continued our emphasis on drilling while also acquiring strategic producing properties where we think performance can be enhanced through drilling or through improved operating efficiencies. This strategy increases our economies of scale and takes advantage of the unique skills we develop through operating in particular geographical regions. Our acquisition in 2006 of five producing fields near our successful Lake Washington anchor area in South Louisiana is an example of this type of strategic acquisition.

The diversity of our oil and gas assets held at year-end 2006 exemplifies another way we aim to ensure growth in shareholder value. With three regions in the United States, each with its own distinct characteristics, and a fourth region in New Zealand, we have achieved an effective balance between crude oil and natural gas reserves, between reserves with shorter and longer production lives, and between an assortment of diverse growth opportunities.

During 2006, strong oil prices and record production drove our net cash provided by operating activities for the year to $424.9 million, the best in the history of the company and an increase of 49% over 2005. Per diluted share, cash flows rose 45% in 2006 to $14.16, and EBITDA (a measure of cash flows, see Glossary on page 77), rose 46% to $456.2 million. Strong oil prices also led to increases in cost and expenses across our industry in 2006 as demand for field services and equipment increased at a rapid pace. Despite the pressures on production costs and the fact that changes in accounting rules require the expensing of stock compensation, we managed to limit our combined production and net general and administrative expenses to 26% of the average per-unit sales price we received in 2006, which is within our long-term strategic goal of keeping these costs below 33%.

Finding costs were under pressure during 2006 as the number of U.S. wells drilled rose 22%, footage drilled climbed 22%, and demand for seismic crews was up 11%. For our company, per-unit reserves replacement costs represented 50% of average sale prices in 2006, which is above our strategic goal of below 33%.

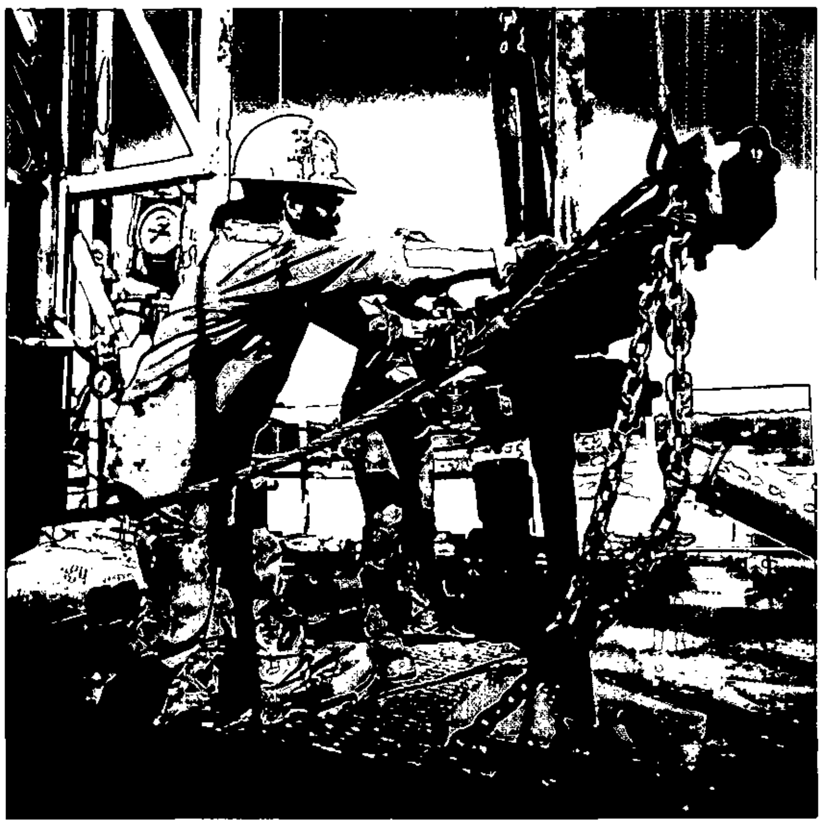
We continually strive to lower and to closely monitor our finding costs. In 2006, our finding costs were directly impacted not only by industry-wide pressures but, among other factors, also by the strategic decision we made to invest for future growth in shareholder value. As noted elsewhere in this report, steps we have taken include expanding our high-tech digital infrastructure, adding personnel with technical expertise, developing a cutting-edge geoscience database covering a broad swath in our South Louisiana region, acquiring additional seismic data in New Zealand, and making significant progress toward facility capacity upgrades. Though these steps have added to our costs and expenses, we believe that our upfront efforts will provide synergies far into the future, helping to reduce costs and build shareholder value over the longer term.

Regions of Operation

Integrating Bright Ideas

Throughout much of its 27-year history, our company has strived to combine conventional oil and gas technologies with appropriate advanced technologies in order to identify elusive pools of hydrocarbons in the earth's crust. Like other companies, we have historically relied on geologists' interpretations of well logs for wells already drilled in the areas of interest, and whenever possible, we have correlated the geologists' data with seismic data for the same areas. While the early seismic datasets were usually limited in scope, recent advances in seismic technology have resulted in an increasing number of more reliable datasets, which with the proper processing and interpretation can yield three-dimensional images of the earth's substructure at depths that can be measured in miles. Other seismic technologies can identify "bright spots" suggesting the possible presence of hydrocarbons within subsurface structures. The result is a series of improved techniques that can lower the risk of finding oil and gas.

With increasing numbers of three-dimensional seismic datasets available for licensing, as well as many oil and gas companies performing surveys to acquire their own data, more and more companies engaged in exploration are developing computer-based techniques for processing and interpreting the data, Swift Energy among them. Since 2004, we have dedicated a significant portion of our exploratory effort to the acquisition and analysis of three-dimensional seismic data. Moreover, we have been digitally integrating our seismic data with geological data in all-inclusive databases, and we can now report the initial results from the application of our first integrated database in our South Louisiana Region of operation.



South Louisiana is one of four geographic regions in which we have large field operations. We began operations there in 2001 when we purchased our first interests in the Lake Washington Field in Plaquemines Parish. Since then, we have added interests in several nearby parishes, to the extent that the region held 53% of the company's total year-end 2006 proved reserves. Because most of the reserves produced in the region to date are long lived with individual wells producing for years, and because they are predominantly crude oil that is in high demand, we have focused heavily on this region during the past five years. Fortunately, it is also the region that was the best candidate for building our first integrated geophysical and geological database.

Our second largest domestic region of operations is in South Texas, where we acquired our first interests in the AWP Olmos Field in McMullen County in 1988. This field also has long-lived reserves and has been a steady producer for us for 18 years, with a mix of approximately 70% natural gas and 30% liquid hydrocarbons. At year-end 2006, our South Texas properties, including some interests outside the AWP Field, held 18% of the company's total reserves.

A third domestic region of operations called Toledo Bend spans the Texas-Louisiana border. We began operations in Toledo Bend in mid-1998 when we purchased properties in contiguous Texas counties and Louisiana parishes and have since acquired other properties nearby. The reserves in this region, which are approximately 65% crude oil, are largely short lived and at year-end 2006 represented 14% of the company's total reserves.

Our fourth geographic region of operations is located in New Zealand, where we began operations following a 1999 discovery on the country's North Island. With subsequent property acquisitions, that region at year-end 2006 held 13% of our total reserves, of which approximately half was oil. In keeping with our emphasis on obtaining seismic databases, we are considering a large three-dimensional seismic survey in New Zealand in the future.

These four regions have resulted from our long-term strategy of concentrating our operations within specific geographic regions and retaining operational control. At year-end 2006, we were operating 94% of our total reserves base. Together, the four regions also fulfill our criterion for maintaining a balanced reserves base.

We, of course, are also always looking for other regions that might fulfill our operational criteria, and during 2006 we participated in a joint-venture onshore exploratory well in the Cook Inlet Basin of Alaska. Although the well was unsuccessful, the area has multiple targets with both oil and gas potential, and we are considering drilling a second joint-venture well there in 2007.

At year-end 2006 we were operating 1,012 wells throughout our regions, including 39 service wells. During 2006 we completed 45 of 63 wells for an overall drilling success rate of 71%. But for the area covered by the integrated database—our Lake Washington Field in South Louisiana—we had an 86% success rate, completing 18 of 21 wells. For the years 2001 to 2006, our average drilling success rate for Lake Washington has been 76%.

In 2006 our total company production increased 18% from our hurricane-affected 2005 production to a record 70.2 billion cubic feet equivalent (Bcfe), with our domestic production increasing 32% to a record 56.7 Bcfe, or 81% of the total. Of these amounts, Lake Washington contributed 38.7 Bcfe, or 55% of our total company production. At the same time, our year-end proved reserves increased 7% above our 2005 reserves to 816.8 Bcfe from a combination of both drilling successes and strategic acquisitions. We added 72.8 Bcfe from drilling activities and 77.7

Distribution of Swift Energy's Proved Reserves (as of December 31, 2006)

	Proved Reserves [a] (Bcfe)			Percent of Company's Reserves	Percent Natural Gas
	Developed	Undeveloped	Total		
Louisiana					
South Louisiana					
Bay de Chene	9.5	7.0	16.5	2.0%	21.6%
Cote Blanche Island	12.2	74.7	86.9	10.6%	34.4%
Lake Washington	126.1	115.8	241.9	29.6%	6.6%
Other South Louisiana [b]	36.8	53.4	90.2	11.1%	75.1%
Toledo Bend					
Masters Creek	13.8	32.0	45.8	5.6%	30.8%
South Bearhead Creek	11.5	26.4	37.9	4.6%	34.7%
Total Louisiana	209.9	309.3	519.2	63.6%	27.8%
Texas					
South Texas					
AWP Olmos	98.6	47.8	146.4	17.9%	69.8%
Other South Texas	2.5	0.6	3.1	0.4%	93.8%
Toledo Bend					
Brookeland	14.3	15.3	29.6	3.6%	42.6%
Other Texas	0.2	0.0	0.2	0.0%	99.9%
Total Texas	115.6	63.8	179.4	22.0%	65.8%
Other States & Federal Offshore	8.4	3.5	11.9	1.5%	61.7%
Total Domestic	333.9	376.6	710.4	87.0%	38.0%
New Zealand					
Rimu/Kauri	15.6	61.3	77.0	9.4%	42.9%
TAWN	11.5	17.9	29.4	3.6%	72.9%
Total New Zealand	27.1	79.3	106.4	13.0%	51.2%
Total Company	361.0	455.8	816.8	100.0%	39.7%

[a] See definitions of proved reserves, proved developed reserves, and proved undeveloped reserves on page 78.

[b] Other South Louisiana includes the Bayou Sale, Horseshoe Bayou, Jeanerette, High Island, and Bayou Penchant properties purchased during 2006.

Bcfe from strategic acquisitions, primarily in South Louisiana. At year-end, 455.8 Bcfe (56%) of our reserves were undeveloped.

Our total capital expenditures for 2006 were $557.5 million, with $214.9 million spent on domestic development drilling and supporting activities and $20.5 million spent on domestic exploration. Domestic strategic property acquisitions totaled $200.5 million, with another $51.1 million spent on domestic prospects. Corresponding costs in New Zealand were $28.8 million on development drilling and associated activities, $15.7 million on exploration, and $10.4 million on prospects.

Our initial 2007 capital budget, which may increase as the year progresses, is $350 million to $400 million, excluding property acquisitions, with approximately 95% expected to cover domestic projects, again primarily in South Louisiana. From this program we are anticipating a total production increase of 7% to 10% above our 2006 production and a proved reserves increase of 4% to 6% above year-end 2006 reserves.

SOUTH LOUISIANA REGION

Our South Louisiana properties increased considerably in acreage and reserves during 2006, through both drilling and acquisitions. We have anchor areas in three different fields in the region—Lake Washington, Bay de Chene, and Cote Blanche Island—and through a large strategic acquisition we added properties in five other fields during 2006. All the anchor areas are located in inland waters, and drilling and completion operations are conducted from barge-based rigs. The properties acquired in 2006 are largely land based, but the abundance of surrounding waters and canals may lead to some barge-based operations in these fields as well. As in the past several years, during 2006 we were the largest crude oil producer in the state of Louisiana.

It is in this region, first in Lake Washington and subsequently in other areas, that we are building what we believe will become the largest contiguous database of three-dimensional seismic data reprocessed and integrated with geological data for the onshore of Louisiana of any company in the industry. In assembling the database, we are merging proprietary data from our own three-dimensional seismic surveys in our anchor areas with

Distribution of Wells in Which Swift Owned Interests (as of December 31, 2006)

	Wells Operated by Swift [a]	Wells Operated by Others	Total Wells	Percent of Swift's Year-end Proved Reserves	Percent of Swift's 2006 Production
Louisiana					
South Louisiana					
Bay de Chene	16	0	16	2.0%	2.8%
Cote Blanche Island	18	0	18	10.6%	1.6%
Lake Washington	145	9	154	29.6%	55.1%
Other South Louisiana [b]	46	48	94	11.1%	1.6%
Toledo Bend					
Masters Creek	85	27	112	5.6%	2.4%
South Bearhead Creek	26	0	26	4.6%	0.9%
Total Louisiana	336	84	420	63.6%	64.3%
Texas					
South Texas					
AWP Olmos	540	0	540	17.9%	10.6%
Other South Texas	8	3	11	0.4%	1.7%
Toledo Bend					
Brookeland	64	28	92	3.6%	3.0%
Other Texas	5	3	8	0.0%	0.0%
Total Texas	617	34	651	22.0%	15.3%
Other States & Federal Offshore	10	6	16	1.5%	1.1%
Total Domestic	963	124	1,087	87.0%	80.8%
New Zealand					
Rimu/Kauri	25	0	25	9.4%	9.0%
TAWN	24	0	24	3.6%	10.2%
Total New Zealand	49	0	49	13.0%	19.2%
Total Company	1,012	124	1,136	100.0%	100.0%
Percent of Reserves	94%	6%			
Percent of Production	98%	2%			

[a] Swift is the operator of 973 producing wells and 39 service wells. The Company has interests in 1,085 producing wells and 51 service wells.

[b] Other South Louisiana includes the Bayou Sale, Horseshoe Bayou, Jeanerette, High Island, and Bayou Penchant properties purchased during 2006.

licensed data for the same or nearby areas. We are reprocessing all the original data from these various sources to very high and consistent specifications, combining them with similarly collected geological data. Eventually we will end up with a high-quality integrated database that will extend across a number of parishes and will be entirely proprietary to Swift. As the reprocessing is completed for specific areas, the data immediately become an important tool for both identifying exploratory prospects and selecting more precise locations for development wells. As noted above and discussed further below, the first subset of this tool has already been successfully used in Lake Washington.

The expanding database will be particularly useful to us for studying very deep target formations. Industry maps of South Louisiana wells show that while essentially all the state's southern parishes have been heavily drilled, many areas exist where exploration

wells exceeding depths of 10,000 feet are sparse or nonexistent and wells drilled to 20,000 feet are rare. To properly assess these deep targets, we are performing prestacked depth migration analyses of the data to account for possible displacements in the visual images we produce by distortions introduced by the extended times and distances traveled by the sound waves during the surveys. These analyses are also required for targets near or beneath salt domes, such as exist in a number of our fields.

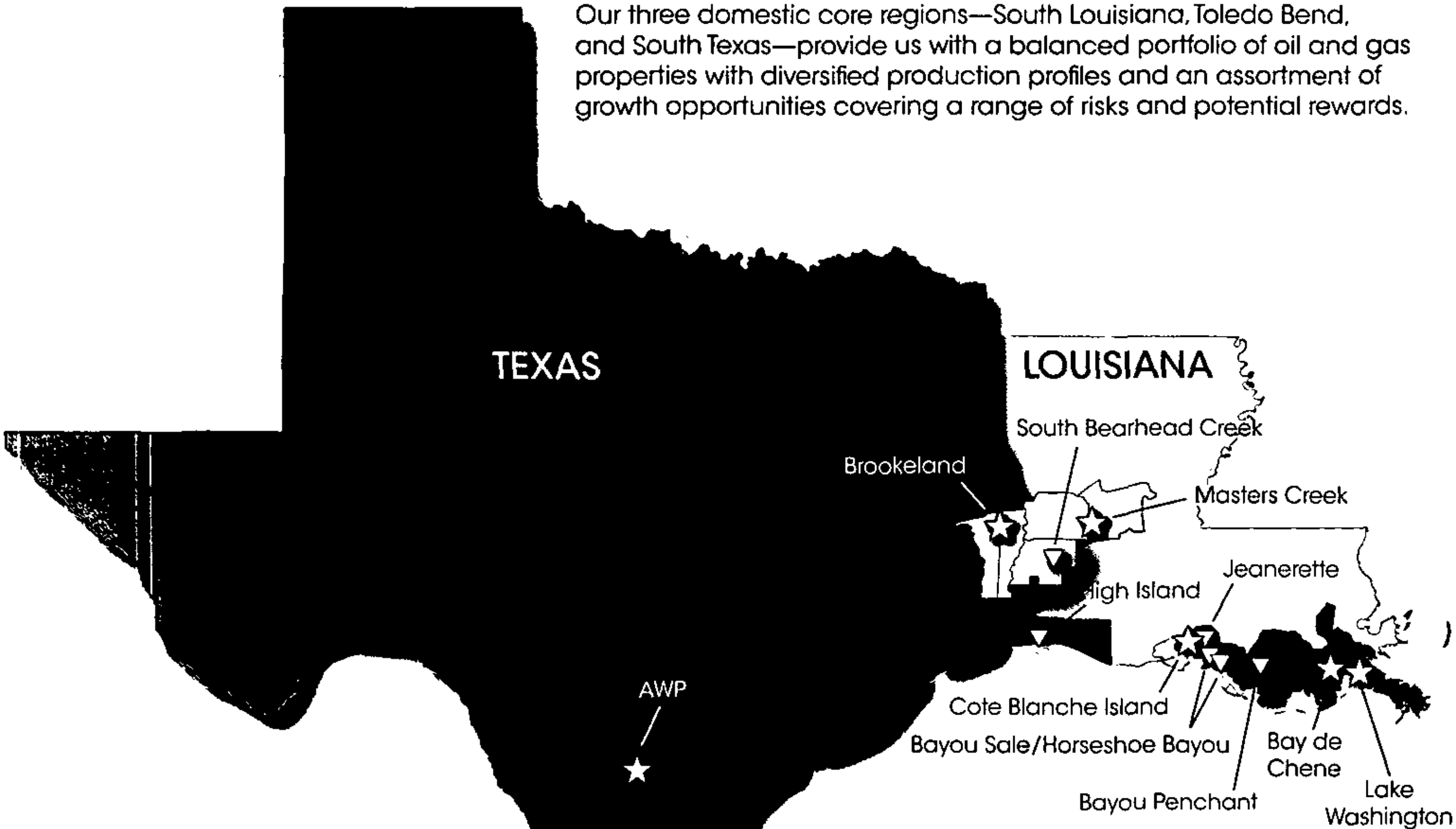
Work on expanding the database will be ongoing for several years, with up to $13 million of our 2007 capital budget allocated for continuing efforts on this project.

LAKE WASHINGTON Our largest asset in South Louisiana is in the Lake Washington Field located in Plaquemines Parish. During 2006, this field alone provided 68% of our total domestic production. When we acquired our first interests in the field in 2001, it was producing less than 1,000 gross barrels of oil per day, and the net reserves that we acquired were estimated at 7.7 million barrels of oil equivalent (MMBOE). During the fourth quarter of 2006, we produced an average of approximately 20,000 gross barrels per day (18,700 net barrels per day) from the field, and its year-end proved reserves (47.9% undeveloped) were 40.3 MMBOE, representing 29.6% of our total year-end 2006 reserves.

Primarily an oil field—year-end reserves were 93% crude oil and NGLs—Lake Washington produces from multiple stacked Miocene sand layers that radiate outward and downward from the surface of a centrally located salt dome having surface depths that vary from 1,200 feet at its peak down to about 14,000 feet over most of our acreage. The field, which is covered by inland waters 2 feet to 12 feet deep, is heavily faulted so that the sands are contained in many isolated reservoirs. The hydrocarbons in each reservoir block tend to migrate upward into the higher regions of the sand layers that are closest to the salt dome, and for fault blocks actually abutting the dome, the higher regions lie against the dome's surface. In order to intercept as many of these as possible in each well, we employ directional drilling from the barge-based rigs so that the well bores angle down the slope of the dome's surface. In general, we complete all the wells in the field to sequentially produce from only one sand at a time, from the deepest upward. From 2001 through 2006, we drilled 173 wells in Lake Washington and completed 131 wells with an average net pay of 149 feet. Together with wells acquired, we had 154 wells at year-end 2006.

Our initial drilling in the field was primarily to relatively shallow depths of 1,500 feet to 6,000 feet, where we consistently found multiple oil pay zones in the stacked sands, some in sands not previously known

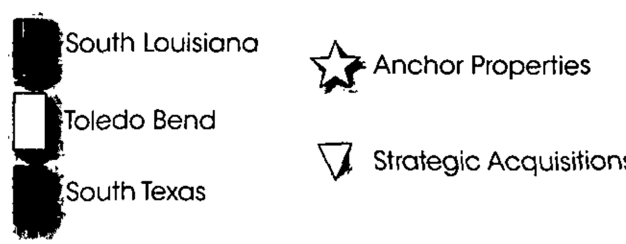
Our three domestic core regions—South Louisiana, Toledo Bend, and South Texas—provide us with a balanced portfolio of oil and gas properties with diversified production profiles and an assortment of growth opportunities covering a range of risks and potential rewards.



to have been productive. By 2003, our drilling activity had increased to 58 wells, with 47 wells successfully completed. But because we wanted to drill to deeper sands for which geological data were sparse and in which we expected to find both oil and natural gas, we made the decision to curtail our drilling program in 2004 in order to conduct a three-dimensional seismic survey over our entire 55-square-mile acreage. These data were immediately merged and reprocessed with additional licensed three-dimensional seismic data for a 530-square-mile area northwest of Lake Washington, and the results were available in time for use in determining the locations of some of Lake Washington's 2005 wells.

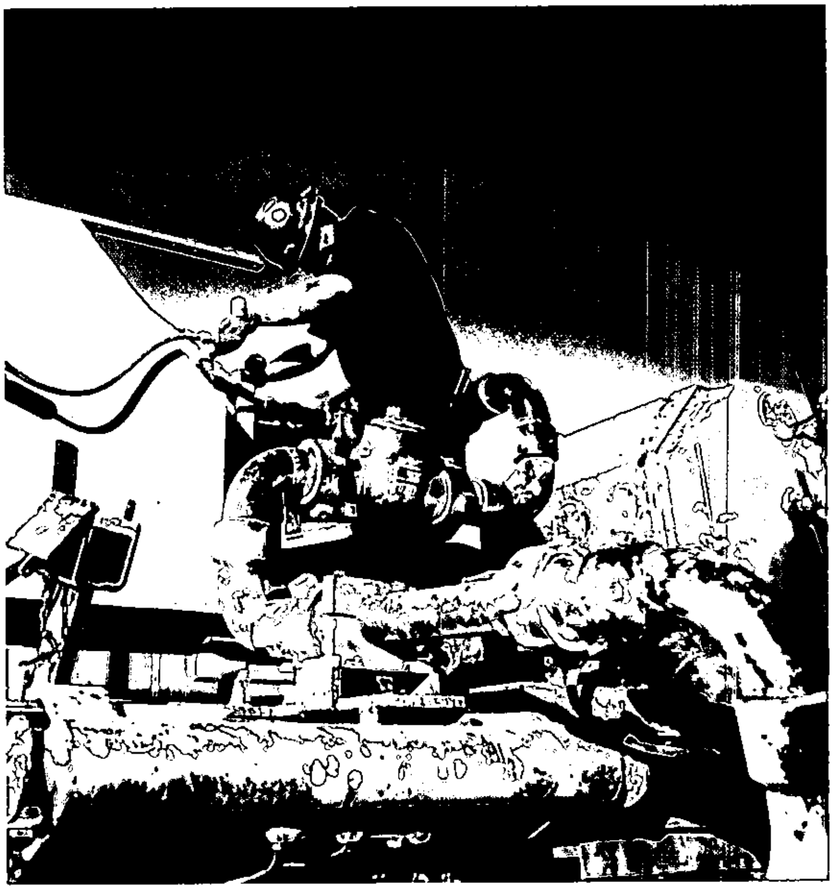
Among the wells drilled in 2005 was a second-quarter exploratory well on the first prospect identified by the new database—the Newport prospect located on the northwest flank of the field's salt dome. This well found 44 feet of pay in a new sand at a depth of 10,418 feet, and it tested at 1,823 barrels of oil and 1.32 million cubic feet of natural gas (MMcf) per day. Because of the onslaught of Hurricane Katrina, the Lake Washington drilling program was again curtailed until the fourth quarter of 2005 when both a Newport delineation well and another prospect—the Bondi prospect five miles northwest of the salt dome—were drilled to depths of 12,736 feet and 13,649 feet, respectively. Both wells found multiple pay zones that were highly productive.

CORE REGIONS ALONG THE U.S. GULF COAST



The remoteness of the Bondi prospect delayed its contribution to Lake Washington's production until a new flow line was connected to the well in early 2007, but because the Newport prospect had access to existing infrastructure, the 2006 Lake Washington drilling program, in which 18 wells out of 21 wells drilled were completed, included six more successful Newport delineation wells (two nonoperated with 50% working interests). The six wells ranged in depth from 12,293 feet to 16,488 feet. The deepest well found pay in three sands and tested at 9,205 BOE per day in one sand; however, the results for its deepest sands were inconclusive, initiating an investigation of those sands with a prestacked depth migration analysis of the three-dimensional seismic data.

With its increasing production, the Lake Washington field is once again approaching infrastructure production constraints, although we have benefited over the past year from a three-year infrastructure upgrade that increased the combined capacity of the field's three production processing platforms to 28,000 barrels of oil per day. To alleviate this situation, we are currently building an additional $50 million processing platform in the western portion



of the field that will add an additional 10,000 BOE per day by mid-2008 and facilitate exploitation of the Bondi prospect. At year-end 2006, we had three barge rigs operating in the field and 109 identified drilling locations. Up to 24 development wells with depths ranging from 4,000 feet to 15,000 feet are planned for the 2007 Lake Washington program.

In late 2006, we acquired $20.4 million of additional interests in the Lake Washington Field northeast and southeast of our original acreage. The interests consist of 1.0 million BOE of proved reserves that are 86% crude oil and 36% developed, with working interests varying from 40% to 100%. The new properties cover 2,800 net acres, bringing our total acreage in the field to 21,690 net acres and further ensuring that Lake Washington will be a strong performer for us for years to come.

BAY DE CHENE Our first expansion of the South Louisiana Region beyond Lake Washington occurred when we simultaneously purchased 100% working interests in the Bay de Chene Field and the Cote Blanche Island Field in late 2004 and early 2005. (See discussion on Cote Blanche Island.)

Bay de Chene covers 16,138 net acres and is located about 30 miles northwest of Lake Washington along the common boundary of Lafourche Parish and Jefferson Parish, and, like Lake Washington, it produces from multiple Miocene sands surrounding a central salt dome. When we acquired this property, the field had estimated reserves of approximately 1.23 million BOE and was producing about 250 BOE per day. We initially shut it in for facility upgrades and later for a series of July-September 2005 tropical storms and hurricanes. After Hurricane Katrina, we continued the shut-in for the remainder of the year as we focused on repairing storm damage at Lake Washington.

During the acquisition of Bay de Chene, we also licensed the results of a three-dimensional seismic survey that had been specifically performed for the field and in some areas overlapped the larger regional database built for Lake Washington. During 2006, we improved the quality of the Bay de Chene data by merging and reprocessing them with the earlier data and subsequently used the results to determine the location of a Bay de Chene exploratory well that was spudded in the field in late 2006. Also during 2006, we drilled six development wells in the field, of which three were successful.

During 2007, Bay de Chene will be a field in which we will carry out significant exploratory drilling. We plan to drill one or two exploration wells in the field with depths between 14,500 feet to 19,000 feet. In addition, we plan to drill up to six Bay de Chene development wells at depths of 10,000 feet to 14,000 feet. As in the Lake Washington Field, the targets for all these wells will be derived from our integrated geological and geophysical data set.

During 2006, Bay de Chene provided 2.8% of our total production and its year-end reserves represented 2.0% of our total reserves. The reserves totaled 2.75 million BOE (42.4% undeveloped), a 123% increase over the estimated purchased reserves. At year-end 2006, we had identified five proved undeveloped locations in the field.

COTE BLANCHE ISLAND The Cote Blanche Island Field in which we acquired 100% interests in late 2004 and early 2005 consists of 7,030 net acres located about 100 miles west of Lake Washington in St. Mary Parish. Also like Lake Washington, Cote Blanche Island produces from multiple Miocene sands surrounding a central salt dome. When we acquired this property, the field had estimated reserves of approximately 6.0 million BOE and was producing about 335 BOE per day. As was the case with Bay de Chene, the field was shut in for most of 2005 for a variety of reasons. Production was restored in early 2006.

In order to gain more knowledge about the field's substructure, we carried out a proprietary three-dimensional seismic survey over 77 square miles in and around Cote Blanche Island early in 2006. At year-end, the processing of these data was nearing completion. In the meantime, we had drilled three development wells in the field, all of which were successful. The first well was logged to a depth of 13,814 feet and found 77 feet of net pay in its primary targeted sand. In 2007 we plan to carry out numerous improvements in the field, including several workovers of operating wells, and also to drill one deep well (to 17,500 feet).

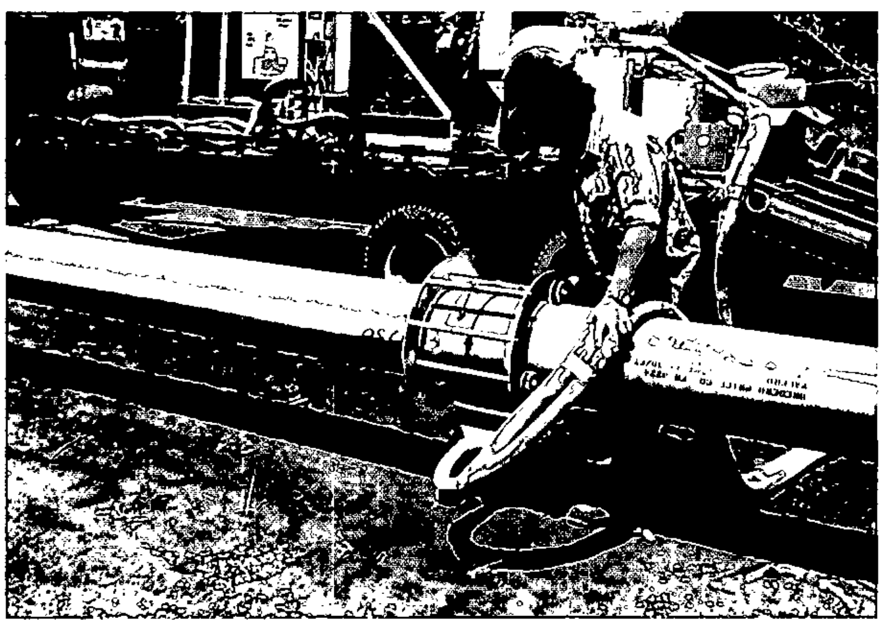
During 2006, Cote Blanche Island provided 1.6% of the company's total production and its year-end reserves represented 10.6% of the company's total reserves. The reserves totaled 14.5 million BOE, a 141% increase over the estimated purchased reserves. At year-end, we had identified 26 undeveloped locations in the area.

BAYOU SALE, HORSESHOE BAYOU, JEANERETTE, HIGH ISLAND, AND BAYOU PENCHANT In August 2006, we announced the largest acquisition in our company's history with a $167.9 million purchase of strategic properties from BP America Production Company in five additional South Louisiana fields: Bayou Sale, Horseshoe Bayou, and Jeanerette in St. Mary Parish; High Island in Cameron Parish; and Bayou Penchant in Terrebonne Parish. During the first half of 2006, the total net daily production from the fields, which is 75% natural gas, had averaged 12 MMcfe (million cubic feet of gas equivalent), and the combined reserves at the time of purchase were estimated to be 58.2 Bcfe of proved reserves (67% developed) and 28.1 Bcfe of probable reserves. Our year-end analysis of company reserves increased the proved reserves for these five properties to 90.2 Bcfe, or 11.1% of our total reserves.

Bayou Sale and Horseshoe Bayou are adjacent to each other and located 13 miles southeast of our anchor area Cote Blanche Island. They produce from several formations at depths of 10,000 feet to 14,000 feet, averaging 6.3 MMcfe net per day during the first six months of 2006. Jeanerette is positioned on the flank of a large salt dome 12.5 miles north of Cote Blanche Island and averaged 1.2 MMcfe net per day from the Planulina sands at depths of 10,000 feet to 15,000 feet. We have already identified up to 15 future development drilling opportunities for Bayou Sale and Horseshoe Bayou and are considering several proved undeveloped locations for Jeanerette.

High Island in Cameron Parish is 65 miles west of Cote Blanche Island and averaged approximately 2.0 MMcfe net from the Marg Howei and Camerina sands between 15,000 feet and 17,000 feet. Bayou Penchant in Terrebonne Parish is about 44 miles southeast of Cote Blanche Island and is the only one of the five properties not operated by us. It produces from Miocene sands at depths of 7,000 feet to 10,000 feet and averaged 2.5 MMcfe net per day. We are reviewing several operational opportunities in both these fields.

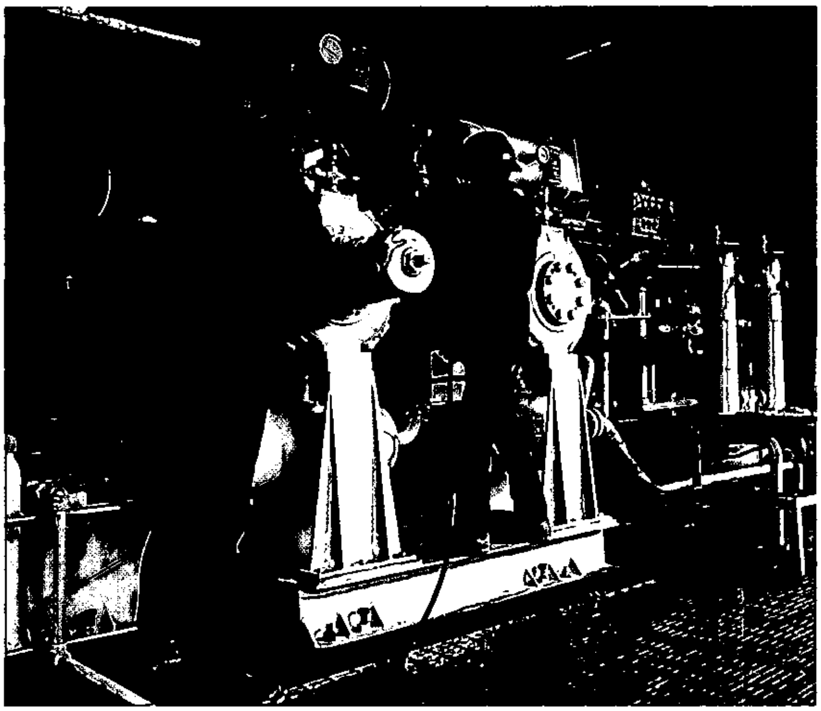
The proximity of these newly acquired properties to Cote Blanche Island greatly increases the value of the data obtained in our recent three-dimensional seismic survey in that area. We have already licensed three-dimensional data for all the new properties, and, except for the High Island data,



we are merging the data with the Cote Blanche Island data for reprocessing into a second integrated geophysical and geological database. This second database then will guide our drilling in all the represented properties as the first database is doing in Lake Washington and Bay de Chene. As noted earlier, our ultimate goal is to develop a comprehensive geophysical and geological database in South Louisiana over most of the area from Plaquemines Parish to Cameron Parish. With our most recent acquisitions, we now have 4,000 square miles of seismic data to include in the comprehensive database. Meanwhile, as work on this effort continues, our operations in these five fields will be ongoing and will include up to four development wells in 2007.

SOUTH TEXAS REGION

South Texas is our oldest region of operation and currently consists almost entirely of our long-time interests in the AWP Olmos Field in McMullen County, Texas. In December 2006 we sold our interests in an area southeast of McMullen County referred to as Garcia Ranch. We still have small interests in a prospective area northeast of AWP.



AWP OLMOS In the AWP Olmos Field we have drilling and production rights on 29,278 net acres. We became an operator in the area in 1989 after purchasing our first interests a year earlier in 65 natural gas wells on a 4,900-acre leasehold. At year-end 2006, we were operating 540 wells in the expanded area with essentially 100% working interests. As is typical of all our operations, in AWP we have followed our strategy of improving efficiency and minimizing costs while maximizing production and minimizing the effects of natural production declines.

AWP wells produce from the field's tight Olmos sand, a depletion-driven reservoir of low porosity and very low permeability located at depths of approximately 9,000 feet to 11,500 feet. Production from the sand is possible only when the sand around the bore hole is hydraulically fractured to provide pathways into the hole and is frequently improved with successive fractures separated in time, the later fractures reaching greater distances as the reservoir pressure declines. Over the years we have greatly improved the fracturing techniques we use and reduced their costs. We performed fractures on 26 wells in the area during 2006 and plan to carry out 18 fractures in 2007.

In another production enhancement technique, we routinely install small-diameter coiled tubing in the well bores during the completion process, thereby restricting the cross section of the upward gas flow to increase its velocity and prevent "liquid loading" of the wells by droplets of condensate in the flow stream dropping back into the wells. In selected cases, we also replace pumping units with a plunger lift mechanism that both increases production and reduces costs. We have also effected cost reductions in the field by adopting slim-hole drilling techniques, monitoring production remotely, and implementing other improvements.

During 2006 we completed 14 of 15 development wells drilled to the AWP Olmos sand, but were unsuccessful with five exploratory wells drilled to a shallow horizon at an aggregate cost of about $0.5 million. AWP provided 10.6% of our total 2006 production and 13.1% of our domestic production. At year-end 2006, the field held 17.9% of our total reserves, of which 69.8% was natural gas and 32.7% was undeveloped, and had 110 proved undeveloped drilling locations.

TOLEDO BEND REGION

Our third domestic region of operation consists of a collection of properties that together are called Toledo Bend because the initial acquisitions in 1998 were near the Toledo Bend Reservoir along the Texas-Louisiana border. The principal fields in those acquisitions were the Brookeland Field located in the Texas counties of Jasper and Newton and the Masters Creek Field located in the Louisiana parishes of Vernon and Rapides, each of which became an anchor area of operation for the company. In 2005, we expanded this region by purchasing strategic properties in South Bearhead Creek Field about 50 miles south of Masters Creek in Beauregard Parish.

BROOKELAND / MASTERS CREEK At year-end 2006, we owned drilling and production rights in 79,593 net acres in Brookeland and 41,988 net acres in Masters Creek, plus 3,500 and 91,594 fee mineral acres in the two fields, respectively.

Both the Brookeland Field and the Masters Creek Field produce from the Austin Chalk trend in which pools of hydrocarbons, primarily crude oil, can be found in natural vertical fractures of the formation. In order to intercept one or more of these fractures, well bores are turned from a vertical direction to a horizontal direction at the depth of the trend. Upon finding the pools, the wells typically have very high initial production rates with relatively rapid decline; i.e., the reserves are considered short lived. In Brookeland, the reserves are depletion driven and generally are found at depths of 7,000 feet to 14,000 feet, whereas in Masters Creek they are water driven and usually found at depths greater than 14,000 feet.

Soon after we closed the Toledo Bend acquisition we quickly upgraded both fields and gained dramatic increases in production and reserves. They have been major producing assets for us for more than eight years, and at year-end 2006 they held 9.2% of our total reserves (3.6% in Brookeland and 5.6% in Masters Creek).

Approximately 63% of the reserves in Masters Creek and Brookeland are undeveloped, primarily because in 2002 we deliberately slowed drilling in these two fields in order to focus on the long-lived reserves in South Louisiana and South Texas. In 2002, we drilled no wells in the Austin Chalk, and only one well in each of the years 2003, 2004, and 2005, all successfully. In 2006, we again drilled a single successful well—a turnazontal well in Brookeland in which two additional horizontal legs were added to a well already possessing two legs. We plan to drill an additional turnazontal well in Brookeland in 2007. As a result of this deliberate slowdown, these two areas contributed only 5.4% of our total production during 2006. At year-end 2006, we had a total of 19 proved undeveloped locations in the two fields.

In April 2006 we sold our minority interest in a natural gas processing plant and related infrastructure in Brookeland that served both fields.

SOUTH BEARHEAD CREEK In two separate acquisitions during the latter part of 2005 we purchased interests in South Bearhead Creek Field in Beauregard Parish, Louisiana, with estimated combined proved reserves of 28.9 Bcfe, or 4.8 million BOE. Approximately 30% of the reserves were proved developed, and the production was mostly oil. We became the operator of all the wells in the field, obtaining 100% working interests in those acquired in the first acquisition and 62.5% working interests in those acquired in the second acquisition. In November 2006, we consolidated our position in South Bearhead Creek by acquiring essentially all the remaining interests and adding another 5.2 Bcfe of proved reserves to our holdings. At year-end 2006, the field's total proved reserves had increased to 37.9 Bcfe, representing 4.6% of our total company reserves.

South Bearhead Creek produces from the upper and lower Wilcox sands at depths of 10,600 feet to 14,100 feet and from the Cockfield sands at depths of 8,000 feet to 8,500 feet. We began our exploitation of the field in 2006 with the completion of three development wells drilled to the Wilcox sand. Early in 2007 we completed an additional well and spudded a fifth well. We plan to drill up to four wells during the year.

At year-end 2006, our interests in South Bearhead Creek totaled 6,258 net acres with 19 drilling locations identified. During 2006, the field contributed 0.9% of our total company production.

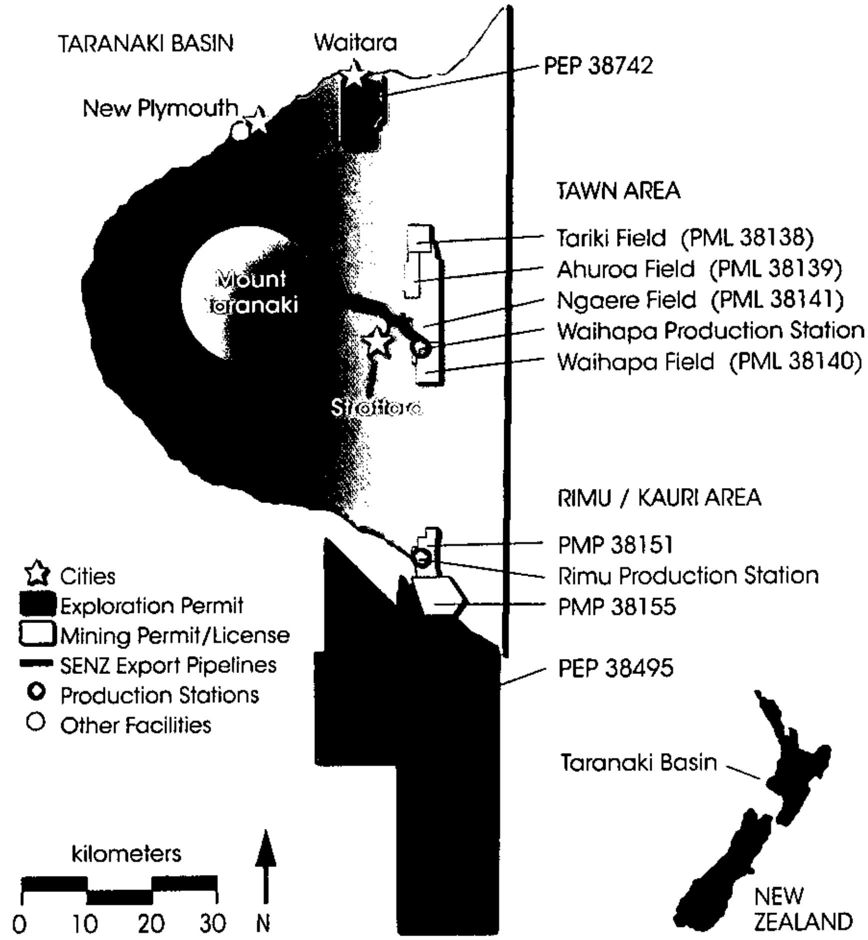
NEW ZEALAND REGION

Our only international region of operation is located in the Taranaki Basin of the North Island of New Zealand. We began operations there in mid-1999 when we drilled a discovery well on a prospect we had identified (the Rimu prospect) after obtaining our first exploration permit in the region in 1995. We subsequently developed the Rimu/Kauri anchor area around this and another prospect (the Kauri prospect) drilled in 2001 approximately 5 miles south of Rimu. In 2002, we added a second anchor area, the TAWN area, with the acquisition of four operating fields about 17 miles to the north of the Rimu discovery. We have also drilled exploration wells in the basin outside the anchor areas. Altogether, at year-end 2006, we had 314,360 gross acres (182,381 net acres) in New Zealand covered by petroleum exploration permits (PEPs), petroleum mining permits (PMPs), and petroleum mining licenses (PMLs) (see map on page 16).

During 2006, New Zealand contributed 19.2% of our total company production and at year-end held 13.0% of our total reserves.

RIMU/KAURI Our Rimu/Kauri anchor area is comprised of two adjacent petroleum mining permits in which we hold 100% interests. One is PMP 38151 that covers approximately 4,552 acres around the Rimu discovery, and the other is PMP 38155 that covers 8,708 acres around the Kauri discovery, for a total area of 13,260 acres. These mining permits were

New Zealand Permit Areas with Swift-Owned Interests



originally inside a larger area covered by PEP 38719, which we no longer hold.

The target sands in Rimu/Kauri are the deep Tariki sands featuring upper and lower sandstone found by the Rimu discovery well at a depth of about 16,000 feet, the intermediate-depth Kauri sands encountered by the Kauri discovery well at approximately 10,000 feet, and a shallow oil-rich Manutahi sand discovered by the Kauri well at about 4,000 feet.

Commercial production from the area began soon after completion of the Rimu Production Station in 2002. After a series of upgrades, the production station at year-end 2006 had a natural gas processing capacity of 24 MMcf per day and an oil capacity of 8,250 barrels per day.

During 2006, we completed two of three development wells drilled in Rimu/Kauri, one to the Kauri and Tariki sands and the other to the Manutahi sand. We were unsuccessful with an exploratory well targeting the Manutahi sand. Development projects in 2007 include several well workovers.

Rimu/Kauri contributed 9.0% of our total 2006 production and at year-end held 9.4% of our total reserves. At year-end 2006, the area had 18 proved undeveloped drilling locations identified.

TAWN Our TAWN anchor area was established in 2002 when we acquired 100% interests in petroleum mining licenses (38138—38141) for four fields: the Tariki and Ahuroa fields, which both produce from the Tariki formation, and the Waihapa and Ngaere fields, which both produce from the Tikorangi formation. The name TAWN is an acronym derived from the first letters of the four field names.

Infrastructure acquired with the TAWN fields included two processing facilities, the Waihapa Oil Plant and the Tariki Ahuroa Gas Plant, both located at the Waihapa Production Station. At year-end 2006, these two processing facilities had a natural gas processing capacity of 42 MMcf per day and an oil capacity of 15,000 barrels per day. They are connected to industry markets by 32-mile oil and gas pipelines.

During 2006, we completed a development well drilled in the Waihapa Field (PML 38140) to the Tikorangi formation. Two exploratory wells, the Goss in PML 38140 and the Trapper in PML 38141, both targeting sands within formations of the Kapuni Group, were unsuccessful. We are considering performing a three-dimensional seismic survey in the area in the future.

TAWN contributed 10.2% of our total 2006 production, and at year-end it held 3.6% of our total reserves with one proved undeveloped location identified.

NONCORE EXPLORATION We have an 80% interest in PEP 38742 that covers 16,794 acres along the northern coast of Taranaki Basin. During 2006, we drilled an exploratory well on the acreage (the Kowhai A-1) that unsuccessfully targeted Eocene-aged Kapuni Group sands in the Mangahewa Field.

In another area of exploration on the southern offshore extension of the Rimu/Kauri structure trend, we conducted a three-dimensional marine seismic survey over 152 square kilometers (59 square miles) in anticipation of drilling a prospect (the Kaheru prospect). We have a 50% interest in this area, which is covered by PEP 38495 and covers 402 square miles (gross).

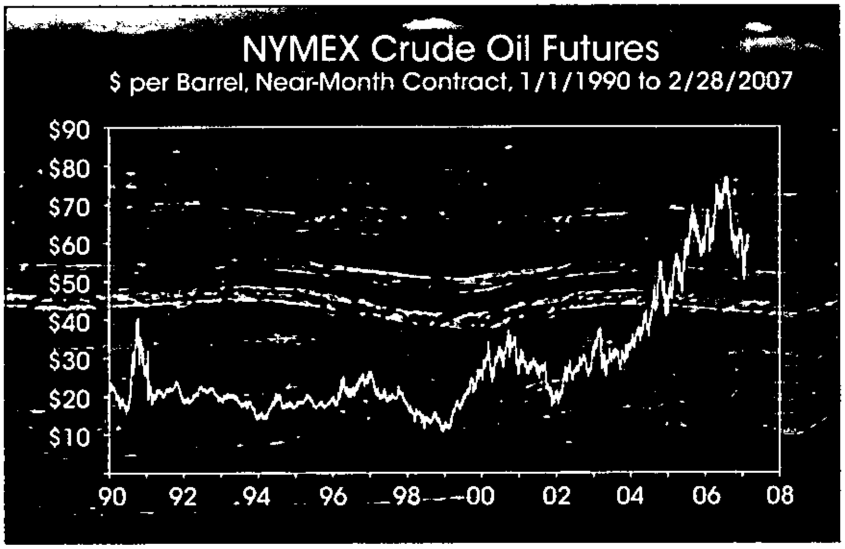
Financial Flexibility

Reflecting Balance & Strength

As we prepare for future growth, maintaining financial flexibility remains the underpinning of all our endeavors, providing us with the means to turn bright ideas into reality and allowing us to take advantage of the opportunities that come our way.

In a disciplined approach to financial management, we provide this flexibility by prudently balancing equity and debt, using capital wisely, aligning our capital expenditures to our cash flows, and maintaining a strategic hedging program that protects near-term cash flows and the capital budget while maintaining upside potential. One tactic we have long practiced is balancing our capital budget between drilling and acquisitions, shifting between the two activities in response to market conditions and strategic opportunities. We generally focus on drilling when oil and natural gas prices are strong, shifting to acquisitions when a strategic opportunity arises or when prices weaken and the per-unit cost of acquisitions becomes more attractive. With this balanced approach, we have been able to grow in a cost-effective manner, replacing 169% of our production, excluding sales of minerals in place, at an average cost of $2.76 per Mcfe over the five-year period through year-end 2006. Other aspects of our financial management approach include matching long-lived assets with long-term financing, establishing leverage targets that are reasonable given the volatility of oil and gas prices, accessing capital markets at opportune times, and continually improving our credit profile.

2006 FINANCIAL OVERVIEW In 2006, our record-high cash flows of $424.9 million, up 49% over 2005 levels, allowed us to expand our capital budget from an initial projection of $300 million to $325 million to expenditures of $557.5 million. More than three-fourths (76%) of these 2006 capital expenditures were covered by net cash provided by operating activities, with the combination of credit facility borrowings, proceeds from property sales, and cash balances providing the remainder. We have a $500 million bank credit facility with a syndicate of 10 banks, which was extended during 2006 through October 2011. At year-end, we had outstanding bank borrowings of $31.4 million, which is less than 13% of our current borrowing base. Additionally, our long-term debt as of year-end 2006 in-



cluded $150 million of 7-5/8% senior notes maturing July 15, 2011, and $200 million of 9-3/8% senior subordinated notes maturing May 1, 2012.

As of December 31, 2006, our total long-term debt comprised approximately 32% of our total book value capitalization. Our debt to PV-10 ratio was 14% at year-end 2006 compared to 11% in 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.

Working capital at year-end fell to a negative $53.4 million, primarily because we invested $194.3 million in strategic acquisitions, the bulk of which was financed with cash balances and net cash provided by operating activities.

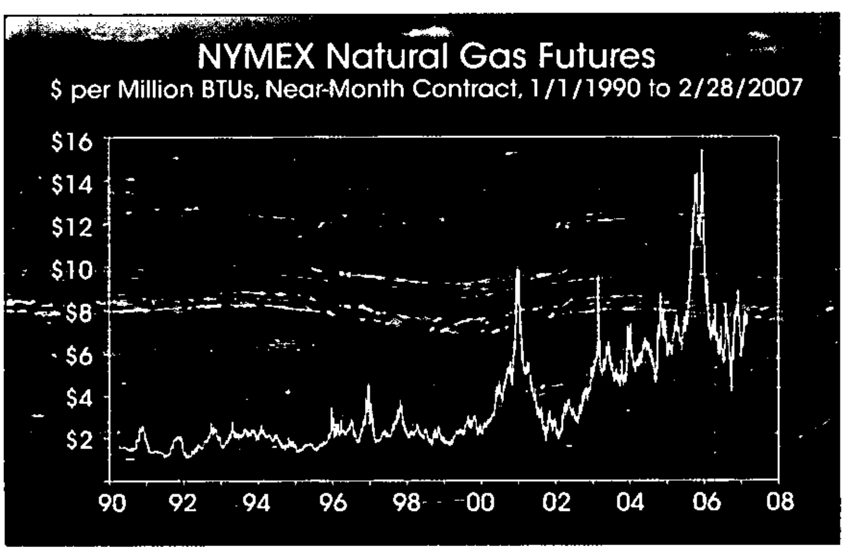
Overall, we continued to maintain a strong liquidity position in 2006 and will strive to do so in the future.

RISK MANAGEMENT As has long been our policy, we focus our price risk management strategy on realizing the benefit of high commodity prices during periods of upswings while protecting against serious pricing downturns. Our company's exposure to volatile commodity prices inherent in the oil and gas industry is our major market risk.

A committee chaired by our president oversees our price risk management program, and its actions must be approved by our chief executive officer. Our hedging strategy is implemented through the use of floors and near-term forward physical sales. We expect to target a portion of our domestic oil and gas production for coverage in 2007, with hedging implemented when market prices are strengthening.

Our risk management of potential natural disasters includes insurance coverage that we consider reasonable and that is similar to that maintained by comparable companies in the oil and gas industry. In 2006, we settled all insurance claims with our insurers related to 2005 damage from hurricanes Katrina and Rita for approximately $30.5 million and entered into a confidential final settlement agreement.

2007 OUTLOOK At the start of 2007, our financial position remains strong and flexible, positioning us to grow organically through drilling and strategically through acquisitions, as well as to meet our goals of becoming digitally integrated and broadening our high-tech capabilities. Our 2007 capital expenditures are currently budgeted at $350 million to $400 million (net of minor non-core dispositions and excluding any property acquisitions), based on the assumption of average 2007 oil prices of $55 per barrel and natural gas prices of $6.50 per MMbtu. During 2007, our capital budget may be revised in response to changes in product prices.



We plan to focus over two-thirds of our capital budget on enhancing our potential in South Louisiana, including continued expansion of our processing facilities for the region and drilling exploratory prospects and development wells based on our digitally integrated three-dimensional geoscience databases. Overall, approximately 95% of our 2007 budget is targeted for domestic activities, primarily in South Louisiana, with about 5% planned for activities in New Zealand. We anticipate funding the majority of our 2007 capital expenditures through cash flows, with access available to our bank credit facility if needed.

Leadership and Management

Setting a Shining Example

With his passing in 2006, Swift Energy's founder A. Earl Swift left many legacies. Among the most important of these were the people-centered values he embedded within the company.

In one of a series of published papers he wrote a few years before his death, he summarized his views on the role of leadership within an organization: "Leaders help others accomplish their individual goals. They help others become part of a team. Most importantly, leaders help others reach beyond themselves to accomplish some greater purpose." He built Swift Energy around his belief that people are the company's greatest asset. For him, helping employees hone their potential—their personal expertise, their ability to interact with one another as a team, and their motivation to achieve a common mission—was the right thing to do for them as individuals and for the company as a whole.

Our emphasis on employee development provides for smooth transitions in succession. At all levels, from the field to the boardroom, our company is set up to maintain stability when the baton of leadership is handed from one person to another. As a result, when Terry Swift was re-elected in 2006 for a three-year term to the Board of Directors and also named its chairman, he had more than 25 years of experience with the company, including six years as a member of the board and five years as chief executive officer, with earlier positions as president and executive vice president.

With respect to the board as a whole, we feel that diversity of its members in both age and skill sets is important and that outside directors should be in the majority, as they have been for many years, to provide a strong measure of external control. Our current board members vary in age from 46 to 75 years, with each selected for the specific area of expertise and unique perspective that he or she can offer in guiding the company. Three-fourths of the members are independent outside directors.

The full board is shown on page 23 of this report. Those re-elected in 2006 include: Raymond E. Galvin, a former president of Chevron U.S.A. Production Company and a member of the board since 2003, who was re-elected for a one-year term and also named vice chairman of the board; Charles J. Swindells, a former U.S. ambassador to New Zealand, who was elected to his first full three-year term; and Clyde W. Smith, Jr., president of electronics manufacturer Ascentron, Inc., and a member of the board since 1984, who was elected to another three-year term.

As we do with our directors, we seek a balance of diverse skill sets and ages among our employees. Over the past three years, the size of our staff has increased by 43% as we have sought talented individuals to add to our in-house mix of skills. At year-end 2006, we had 345 employees, the highest number in our history. Among those recently joining our team are three new vice presidents: Edward A. Duncan, who joined us in February 2006 as vice president of exploration after consulting with our company for several years and having more than 25 years of experience in domestic and international explora-

tion programs, especially along the Gulf Coast and upper Texas coastal plain; David P. Coatney, who in 2006 became vice president of production operations following his oversight of field operations for Swift Energy New Zealand; and D. Gregg Jones, who joined us in 2007 as vice president of corporate administration with over 25 years of human resources management experience.

In another management appointment, Robert J. Banks was named vice president of international operations and strategic ventures of Swift Energy Company in 2006. He also will continue to serve as vice president of international operations of Swift Energy International, a position he has held since 2004.

We know that passing knowledge from one generation to the next will become increasingly critical as our industry matures, with more geoscience professionals scheduled to retire than there are college graduates to replace them. To help address this, we began participation in a University of Texas mentoring program with science teachers and students. This mentoring program is part of our effort to nurture students who may be interested in the oil and gas industry, particularly in the geoscience field. Mentoring takes place within our company as well, with the aim of strengthening the proficiency of professionals in all departments, both individually and as a group.

To further promote professional development, we initiated the cataloguing of individual education, experience, and skills for all of our employees in 2006. These knowledge networks, as we call them, cover three broad areas of expertise—the geoscience, engineering, and commercial/administrative disciplines—and they are designed to track each employee's areas of competence, to more clearly define each employee's role in regard to our mission, and to identify areas of professional development needed to achieve our goals.

These knowledge networks add a third dimension to the matrix organizational structure we have had in place for many years. In addition to grouping our staff by function (exploration, exploitation, operations, and support activities) and by our major regions of operation (South Louisiana, South Texas, Toledo Bend, and New Zealand), we are now also grouping people in our matrix system by our three knowledge networks. This creates a three-dimensional matrix system that offers richer interconnectivity in our organizational relationships, helping us make the most of the collaborative potential generated by the digital revolution that is transforming our industry. Multiple pathways are created for information to flow both up and down the hierarchy and between departments and disciplines, facilitating faster and more reliable flows of information.

To ensure that the full potential of our matrix system is realized, we have well-defined but flexible processes in place to aid in the execution of our strategy. One key control process is our annual budget, which serves as a guide and benchmark for the subsequent year's activity, focusing primarily on planning and forecasting our capital expenditures. In effect, our annual budget serves as the bridge between long-term strategy and day-to-day decision making. After rigorous internal review and debate of various budget scenarios, selected scenarios are presented to the board of directors for final consideration, with the board approving one scenario as the consolidated budget for the coming year.

Implementing projects from the approved budget begins with an authority-for-expenditure process, in which budgeted projects are approved for implementation through a two-tiered process of operating and financial reviews.

Our approval process for budgeted projects was designed to push cooperation and transparency throughout the organization. It forces teamwork and communication between disciplines and departments, and it provides flexibility for responding to unexpected situations. Since the creation of this current process in 2002, our review procedures have proven to be critical tools for setting the tone of our organizational culture.

For longer term planning, we are guided by a well-defined strategic plan that is updated every four to six years, with routine monitoring of our progress toward the plan's goals throughout each year. Our strategic goals have traditionally included financial targets, such as goals for per-share earnings and for the ratio of debt to proved reserves, and operational targets, such as goals for growth in proved reserves and production and for holding down costs and expenses.

Together, the annual budget, the implementation procedure for the budget, and the strategic plan are the key processes we use to guide our company toward achieving our goals. As we carry out our plans for 2007, the groundwork that has been laid in 2006 will continue to take root and grow, moving us toward our vision and honoring the values set in place by Earl Swift.

A Tribute to A. Earl Swift

To know Earl Swift was to respect him. Though he had an unassuming manner, his intellect and wit were apparent to everyone who knew him. His compassion and generosity were also obvious, making him a man not easily forgotten.

Here at Swift Energy, we can recall even more to admire about Earl Swift. We remember him as a strong leader who was consistently fair yet demanded the best we had to give. Always proud of the collective talents he had assembled, he encouraged us to use those talents not only for the good of the company and its shareholders, but also for each other, our families, and the communities in which the company operates. He considered the way we interacted with one another and others outside the company to be of high importance. He repeatedly reminded us that he had founded the company on family values he had been taught, and he expected those values to be adhered to, no matter how big a player we became in the oil and gas industry.

Earl learned those family values early, not only in the home but also while working for the small drilling company owned and operated by his uncles and father Virgil Swift. The Swift brothers put their sons to work in the Oklahoma oil fields as teenagers; thus Earl and his own brothers Virgil Neil and Kenneth Merle (his twin who predeceased him) gained practical field experience and the desire to learn more about the industry.

In 1951, Earl enrolled at the University of Oklahoma, graduating in 1955 with a petroleum engineering degree and an expertise in waiting tables to earn tuition. After a short stint in the U.S. Army, he began his career as a reservoir engineer at Humble Oil Company (a predecessor of ExxonMobil). Seven years later he joined the Michigan-Wisconsin Pipeline Company, whose primary business was natural gas pipeline transmission. With natural gas completely regulated by the federal government at the time, he had frequent interactions with the Federal Power Commission, pushing him into acquiring legal skills. He enrolled in night school classes at South Texas College of Law in Houston and received a law degree in 1968. In 1979, he left Michigan-Wisconsin, where he had become vice president of exploration and production.

His departure was prompted by his unquenchable desire to begin his own oil and gas company. It was a leap of faith. "When an entrepreneur starts a business from scratch with little financial resources," he later wrote, "he finds himself wearing all the hats. I was the engineer, the lawyer, the real estate negotiator, and the geologist." He succeeded despite his multiple responsibilities, and on October 11, 1979, he founded Swift Energy Company.

So that he would not compete with his former employer, Earl chose to begin the company's operations with a conservative drilling program in West Virginia, where, under new regulations, gas from certain reservoirs in the Devonian shale could be sold at negotiated prices. With funds provided by a private drilling fund partnership of friends and colleagues, he launched a drilling program of 10 successful wells that affirmed his reservoir engineering skills and assured a future for Swift Energy Company.

After more than a year of drilling successes in West Virginia, Earl convinced his brother Virgil and his son Terry Earl to join Swift Energy in 1981. To do so, Virgil retired from Gulf Oil Corporation after 28 years in various managerial positions in drilling and production and Terry left his position as a reservoir engineer with H.J. Gruy and Associates, Inc. Virgil became chief operating officer and vice chairman of the board, and Earl retained his positions as president, chief executive officer, and chairman of the board. Working as a management team, the three Swifts successfully expanded the company's drilling program to several other states.

Soon, however, dramatic changes began to occur in the oil and gas industry because of an oversupply of natural gas and plunging oil and gas prices. Earl was the first to recognize that the survival of the company depended on a strategic shift in direction, and in 1983 he refocused the company's activities from drilling activities to the acquisition and operation of oil and gas properties that were already producing. To fund the acquisitions, Swift Energy created and managed public income fund partnerships in which the company itself held interests. In its dual role as both operator and investor, the company enhanced production by improving the properties, sometimes with development drilling.

This strategy served the company well through the next decade, but Earl's plan was to return to the search for oil and gas whenever the industry outlook improved. In anticipation of this, he encouraged the company to build technical teams whose skills could immediately be put to use in selecting and developing partnership properties and in identifying future exploration prospects. He was also keenly aware of the implications of the information age and urged the company to adapt to advanced technologies.

At the same time, Earl felt that he and others in management could better lead Swift Energy in the future with more formal education in business, and he was the first from the company to enroll in the Presidential/Key Executive MBA Program at Pepperdine University. In fulfilling the requirements for graduation in 1988, he produced a seven-year strategic plan for the company that specified oil and gas reserves growth targets for 1995. By the time 1995 arrived, we had exceeded the plan's goals. We also had ceased offering partnership interests and had begun relying on other capital formation strategies.

Earl Swift (center) with son Terry Earl Swift (left) and brother Virgil Neil Swift on a drilling rig floor in 1992.

Under Earl's continuing leadership, several steps by the company had made such progress possible. Deciding to focus on larger properties within limited geographic regions, in 1989 we gained majority interests in a number of wells in the AWP Olmos Field in McMullen County, Texas, and began a highly successful drilling program that continues today with over 500 wells operating. At the same time we acquired properties in the Weatherford Field in Oklahoma, operating them for our partnerships for several years. In 1992, we joined others in the industry in drilling horizontal wells in the Austin Chalk trend in the Texas Giddings Field, drilling 87 horizontal wells with an 84% success rate before completing the program in 2000.

Later, in 1998, still under Earl's watch, we transferred our Austin Chalk expertise to properties we acquired in central Louisiana and an adjoining Texas area (Toledo Bend), and in 1999 we had our first international discovery in New Zealand.

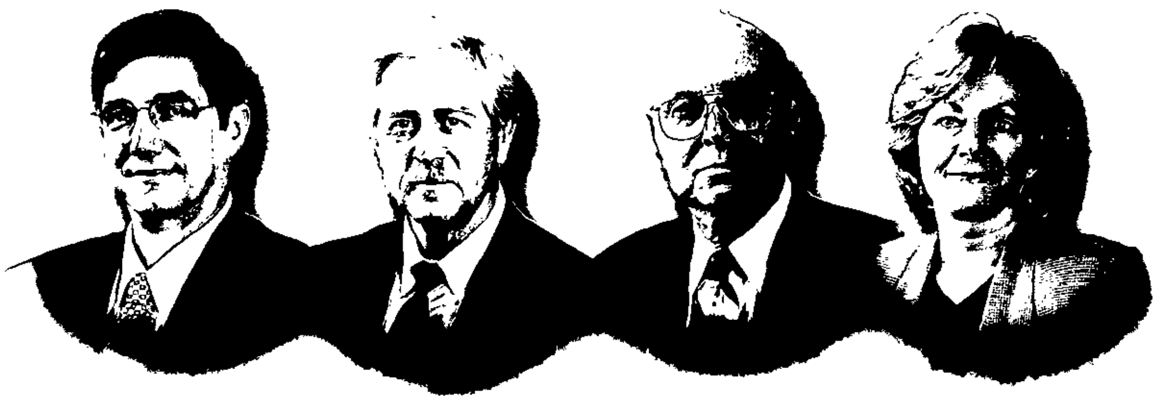
While all these activities were occurring, Earl and Virgil were following well-laid plans for the company's management succession. In 1991, Terry began assuming executive positions, as did others in the company. Virgil retired as an employee in 2000 and from the Board of Directors in 2005. Earl retired as president in 2000 and as chief executive officer in 2001, remaining as chairman of the board but planning to also leave that position in 2007.

Under our new management, we made the most significant acquisition of our history with the purchase in 2001 of our initial interests in the Lake Washington Field in South Louisiana, a move applauded by Earl. He also enthusiastically approved the assistance given by the company to its employees and communities devastated by the effects of hurricanes Katrina and Rita in 2005. It was, he felt, in keeping with his vision of the company as stated in his 25th anniversary letter to the employees: "I see Swift Energy as a company of role models, an organization filled with people who consistently work to change things for the better. I want each of you to know that I am proud to be your chairman and have every confidence that you will continue to do great things in the future."

We shall try, Mr. Chairman. We shall try our utmost.

To read more about Earl Swift and his writings, see: http://www.swiftenergy.com/earlswifttribute/

Board of Directors

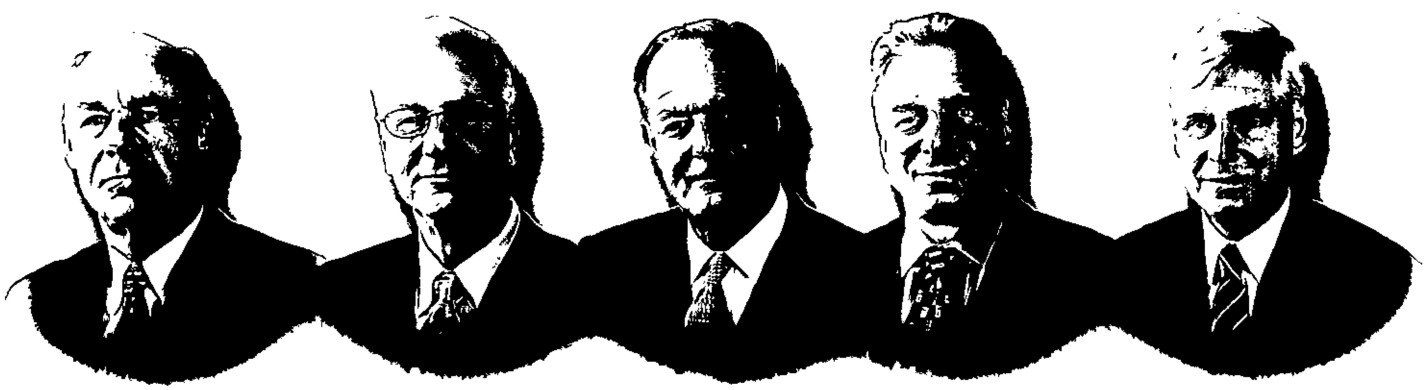


Terry E. Swift
Chairman &
Chief Executive Officer,
Swift Energy Company,
Age 51

Bruce H. Vincent
President,
Swift Energy Company,
Age 59

Raymond E. Galvin
Vice Chairman,
Swift Energy Company,
Retired President, Chevron U.S.A.
Production Company, Age 75

Deanna L. Cannon
Partner,
Corporate Finance Associates
of Northern Michigan,
Age 46



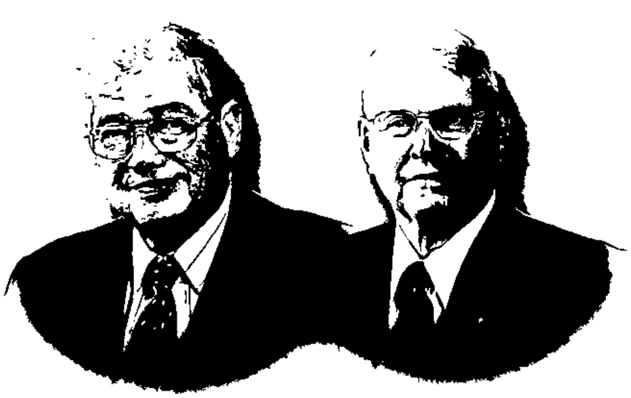
Douglas J. Lanier
Retired Vice President,
Gulf of Mexico Business Unit,
ChevronTexaco Exploration &
Production Company, Age 57

Greg Matiuk
Retired Executive Vice
President, Administrative &
Corporate Services, Chevron-
Texaco Corporation, Age 61

Henry C. Montgomery
Chairman & Founder,
Montgomery Professional
Services Corp., Age 71

Clyde W. Smith, Jr.
President,
Ascentron, Inc.,
Age 58

Charles J. Swindells
Managing Director of
U.S. Trust Company, N.A.,
Age 64



A. Earl Swift
Principal Founder,
Swift Energy Company,
Chairman of the Board
1979-2006

Virgil N. Swift
Founder / Director Emeritus,
Swift Energy Company,
Former Vice Chairman of the Board

Board of Directors Committees:

Audit Committee:
Henry C. Montgomery–Chairman
Deanna L. Cannon, Clyde W. Smith, Jr.

Corporate Governance Committee:
Greg Matiuk–Chairman
Deanna L. Cannon, Raymond E. Galvin, Charles J. Swindells

Compensation Committee:
Clyde W. Smith, Jr.–Chairman
Douglas J. Lanier, Greg Matiuk, Henry C. Montgomery, Charles J. Swindells

Executive Committee:
Terry E. Swift–Chairman
Raymond E. Galvin, Douglas J. Lanier

Company Officers

Terry E. Swift
Chairman & Chief Executive Officer

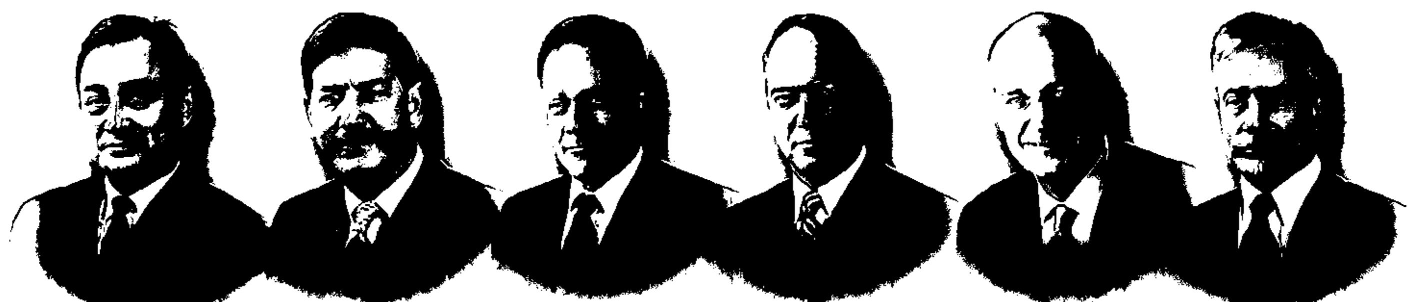
Bruce H. Vincent
President

Joseph A. D'Amico
Executive Vice President & Chief Operating Officer

Alton D. Heckaman, Jr.
Executive Vice President & Chief Financial Officer

James M. Kitterman
Senior Vice President–Operations

James P. Mitchell
Senior Vice President–Commercial Transactions & Land



Victor R. Moran
Senior Vice President & Chief Compliance Officer

Robert J. Banks
Vice President–International Operations & Strategic Ventures

David P. Coatney
Vice President–Production Operations

Edward A. Duncan
Vice President–Exploration

D. Gregg Jones
Vice President–Corporate Administration

Thomas E. Schmidt
Vice President–Exploitation & Development

Tara L. Seaman
Vice President–Reserves & Evaluations

Laurent A. Baillargeon
Chief General Counsel

Karen M. Bryant
General Counsel–Corporate, Chief Governance Officer & Secretary

Adrian D. Shelley
Treasurer

David W. Wesson
Controller

Donald L. Morgan
President, SEI;
Chairman, SENZ

R. Alan Cunningham
President, SENZ

Steven B. Yakle
Treasurer SEI;
Vice President–Finance, Chief Financial Officer & Secretary, SENZ

Christopher J. T. Bush
Vice President–Facilities, SENZ

Financial Report

Selected Financial and Operating Data

	2006	2005	2004	2003
Total Revenues	$615,441,230	$423,226,489	$310,276,774	$208,900,983
Income (Loss) Before Income Taxes and Change in Accounting Principle[1]	$262,286,165	$178,439,551	$101,440,242	$50,739,178
Net Income (Loss)	$161,565,340	$115,778,456	$68,450,917	$29,893,812
Net Cash Provided by Operating Activities	$424,921,046	$285,333,484	$182,582,887	$110,827,279
Per Share Data				
Weighted Average Shares Outstanding[1]	29,265,366	28,496,275	27,822,413	27,357,579
Earnings (Loss) per Share—Basic[1]	$5.52	$4.06	$2.46	$1.09
Earnings (Loss) per Share—Diluted[1]	$5.38	$3.95	$2.41	$1.08
Shares Outstanding at Year-End	29,742,918	29,009,530	28,089,764	27,484,091
Book Value per Share at Year-End	$26.83	$20.94	$16.88	$14.46
Market Price[1]				
High	$51.84	$50.01	$30.34	$18.00
Low	$35.48	$24.77	$15.90	$7.60
Year-End Close	$44.81	$45.07	$28.94	$16.85
Effect on Net Income and Earnings per Share from Changes in Accounting Principles[2]				
Cumulative Effect of Change in Accounting Principle (Net of Taxes)	—	—	—	$(4,376,852)
Effect per Share—Basic	—	—	—	$(0.16)
Effect per Share—Diluted	—	—	—	$(0.16)
Assets				
Current Assets	$92,573,041	$115,055,135	$54,385,996	$33,460,957
Property & Equipment, Net of Accumulated Depreciation, Depletion, and Amortization	$1,483,312,165	$1,079,033,739	$923,438,160	$815,807,003
Total Assets	$1,585,681,758	$1,204,412,622	$990,573,147	$859,838,544
Liabilities				
Current Liabilities	$145,975,288	$98,421,014	$68,618,291	$69,353,342
Long-Term Debt	$381,400,000	$350,000,000	$357,500,000	$340,254,783
Total Liabilities	$787,764,786	$597,094,455	$516,401,007	$462,447,280
Stockholders' Equity	$797,916,972	$607,318,167	$474,172,140	$397,391,264
Number of Employees	345	311	272	241
Producing Wells				
Swift Operated	973	898	835	870
Outside Operated	112	69	97	128
Total Producing Wells	1,085	967	932	998
Wells Drilled (Gross)	63	64	66	75
Proved Reserves				
Natural Gas (Mcf)	324,131,417	287,473,150	318,246,294	335,804,862
Oil, NGL, & Condensate (barrels)	82,119,084	79,053,056	80,267,208	80,759,903
Total Proved Reserves (Mcf equivalent)	816,845,916	761,791,482	799,849,539	820,364,284
Production (Mcf equivalent)[3]	70,204,544	59,589,526	58,318,502	53,158,384
Average Sales Price				
Natural Gas (per Mcf)	$5.05	$5.23	$4.12	$3.42
Natural Gas Liquids (per barrel)[4]	$32.15	$28.04	$22.52	$17.60
Oil (per barrel)[4]	$64.47	$53.63	$40.24	$29.89
Mcf Equivalent	$8.57	$7.11	$5.34	$3.97

[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.

2002	2001	2000	1999	1998	1997	1996
$149,969,811	$183,807,490	$191,624,946	$110,671,007	$82,469,221	$74,712,180	$56,298,026
$18,408,289	$(34,192,333)	$92,449,488	$29,736,151	$(73,391,581)	$33,129,606	$28,785,783
$11,923,227	$(22,347,765)	$59,184,008	$19,286,574	$(48,225,204)	$22,310,189	$19,025,450
$71,626,314	$139,884,255	$128,197,227	$73,603,426	$54,249,017	$55,255,965	$37,102,578
26,382,906	24,732,099	21,244,684	18,050,106	16,436,972	16,492,856	15,000,901
$0.45	$(0.90)	$2.79	$1.07	$(2.93)	$1.35	$1.27
$0.45	$(0.90)	$2.51	$1.07	$(2.93)	$1.26	$1.25
27,201,509	24,795,564	24,608,344	20,823,729	16,291,242	16,459,156	15,176,417
$13.42	$12.61	$13.50	$8.18	$6.71	$9.69	$9.41
$20.58	$37.70	$43.50	$13.31	$21.00	$34.20	$28.86
$6.80	$16.66	$9.75	$5.69	$6.94	$16.93	$9.89
$9.67	$20.20	$37.63	$11.50	$7.38	$21.06	$27.16
—	$(392,868)	—	—	—	—	—
—	$(0.01)	—	—	—	—	—
—	$(0.01)	—	—	—	—	—
$29,768,199	$36,752,980	$41,872,879	$50,605,488	$35,246,431	$29,981,786	$101,619,478
$721,617,941	$628,304,060	$524,052,828	$392,986,589	$356,711,711	$301,312,847	$200,010,375
$767,005,859	$671,684,833	$572,387,001	$454,299,414	$403,645,267	$339,115,390	$310,375,264
$46,884,184	$73,245,335	$64,324,771	$34,070,085	$31,415,054	$28,517,664	$32,915,616
$324,271,973	$258,197,128	$134,729,485	$239,068,423	$261,200,000	$122,915,000	$115,000,000
$401,932,675	$359,032,113	$240,232,846	$283,895,297	$294,282,628	$179,714,470	$167,613,654
$365,073,184	$312,652,720	$332,154,155	$170,404,117	$109,362,639	$159,400,920	$142,761,610
234	209	181	173	203	194	191
820	854	817	769	836	650	842
112	381	711	788	917	917	986
932	1,235	1,528	1,557	1,753	1,567	1,828
36	53	70	27	75	182	153
326,731,672	324,912,125	418,613,976	329,959,750	352,400,835	314,305,669	225,758,201
70,438,963	53,482,636	35,133,596	20,806,263	13,957,925	7,858,918	5,484,309
749,365,449	645,807,939	629,415,552	454,797,327	436,148,385	361,459,177	258,664,055
49,752,346	44,791,202	42,356,705	42,874,303	39,030,030	25,393,744	19,437,114
$2.30	$4.23	$4.24	$2.40	$2.08	$2.68	$2.57
$12.82	—	—	—	—	—	—
$24.52	$22.64	$29.35	$16.75	$11.86	$17.59	$19.82
$2.84	$4.05	$4.47	$2.54	$2.05	$2.72	$2.71

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 36 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.

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:

	Oil and Gas Sales (In millions)			Oil and Gas Sales Volume (Bcfe)		
Area	2006	2005	2004	2006	2005	2004
AWP Olmos	$ 53.7	$ 61.7	$ 49.9	7.5	7.7	9.0
Brookeland	15.6	20.4	18.0	2.1	2.9	3.4
Lake Washington	397.2	229.2	152.3	38.7	26.7	23.2
Masters Creek	13.3	17.9	21.0	1.7	2.4	3.7
Cote Blanche Island / Bay de Chene	29.3	7.4	0.0	3.1	0.9	0.0
Other	28.4	19.3	17.5	3.6	2.4	2.8
Total Domestic	$ 537.5	$ 355.9	$ 258.7	56.7	43.0	42.1
Rimu/Kauri	36.8	41.6	24.5	6.3	8.2	5.3
TAWN	27.2	26.3	28.1	7.2	8.3	11.0
Total New Zealand	$ 64.0	$ 67.9	$ 52.6	13.5	16.5	16.3
Total	$ 601.6	$ 423.8	$ 311.3	70.2	59.6	58.3

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:

- 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
- 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 Price		
		Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (Bcfe)	Oil (Bbl)	NGL (Bbl)	Natural Gas (Mcf)
2004:	First	1,124	277	5.9	14.3	$34.14	$22.30	$3.64
	Second	1,142	269	5.8	14.3	$37.24	$18.84	$4.19
	Third	1,076	251	6.0	13.9	$41.99	$23.33	$3.97
	Fourth	1,380	243	6.1	15.9	$46.33	$26.01	$4.67
	Total	4,722	1,040	23.7	58.3	$40.24	$22.52	$4.12
2005:	First	1,321	223	6.3	15.5	$47.66	$26.79	$4.25
	Second	1,426	209	6.1	15.9	$50.24	$22.95	$4.67
	Third	1,059	204	5.9	13.5	$59.66	$31.84	$5.29
	Fourth	1,353	202	5.3	14.7	$58.31	$30.83	$6.97
	Total	5,159	838	23.6	59.6	$53.63	$28.04	$5.23
2006:	First	1,611	152	6.0	16.5	$60.83	$30.34	$5.38
	Second	1,636	138	5.6	16.3	$69.63	$29.72	$4.79
	Third	1,992	220	5.5	18.8	$69.62	$36.18	$4.87
	Fourth	1,951	203	5.7	18.6	$57.88	$30.79	$5.14
	Total	7,190	713	22.8	70.2	$64.47	$32.15	$5.05

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	2011	Thereafter	Total
				(In thousands)			
Non-cancelable operating leases[1]	$ 5,345	$ 5,321	$ 3,334	$ 3,293	$ 3,225	$ 10,109	$ 30,627
Asset retirement obligation[2]	1,650	2,313	2,019	2,110	2,205	24,163	34,460
Computer system implementation	3,261	—	—	—	—	—	3,261
Construction costs	5,223	—	—	—	—	—	5,223
Drilling rigs, seismic and pipe inventory	28,873	—	—	—	—	—	28,873
7-5/8% senior notes due 2011[3]	—	—	—	—	150,000	—	150,000
9-3/8% senior subordinated notes due 2012[3]	—	—	—	—	—	200,000	200,000
Credit facility[4]	—	—	—	—	31,400	—	31,400
Total	$ 44,352	$ 7,634	$ 5,353	$ 5,403	$ 186,830	$ 234,272	$ 483,844

[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 redetermined 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; and
- $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; and

- $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:

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

New Zealand expenditures of $48.7 million as follows:

- $27.2 million for drilling costs and developmental activity costs, predominantly in our Rimu/Kauri area;
- $13.6 million on exploratory drilling;
- $6.9 million on prospect costs, principally prospect leasehold, seismic and geological costs of unproved properties;
- $0.8 million on gas processing plants; and
- $0.2 million for computer equipment, software, furniture, and fixtures.

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

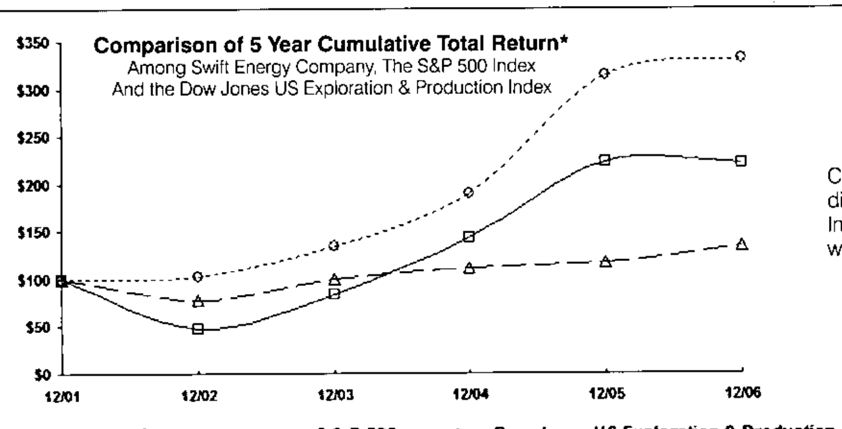
We were the operator of a number of properties owned by affiliated limited partnerships and, accordingly, charge these entities operating fees. The operating fees charged to the partnerships totaled the same $0.2 million in 2006, 2005 and 2004, and are recorded as reductions of general and administrative, 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.



www.researchdatagroup.com/S&P.htm

*$100 invested on 12/31/01 in stock or index-including reinvestment of dividends. Fiscal year ending December 31.

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.

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 on Internal Control Over Financial Reporting

The Board of Directors and Stockholders of Swift Energy Company

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting that Swift Energy Company maintained effective internal control over financial reporting as of December 31, 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 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 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

ERNST & YOUNG LLP

Houston, Texas
February 27, 2007

Report of Independent Registered Public Accounting Firm on Consolidated Financial Statements

The Board of Directors and Stockholders of Swift Energy Company

We have audited the accompanying consolidated balance sheets of Swift Energy Company and subsidiaries as of December 31, 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's 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

ERNST & YOUNG LLP

Houston, Texas
February 27, 2007

Consolidated Balance Sheets

Swift Energy Company and Subsidiaries

	Year Ended December 31, 2006	Year Ended December 31, 2005
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 1,058,051	$ 53,004,562
Accounts receivable—		
Oil and gas sales	63,935,441	45,518,260
Joint interest owners	1,843,824	1,082,187
Other receivables	1,231,384	3,795,080
Deferred tax asset	2,383,176	—
Other current assets	22,121,165	11,655,046
Total Current Assets	92,573,041	115,055,135
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	2,264,831,638	1,731,866,298
Unproved properties	112,136,836	87,553,220
	2,376,968,474	1,819,419,518
Furniture, fixtures, and other equipment	28,040,405	15,313,277
	2,405,008,879	1,834,732,795
Less — Accumulated depreciation, depletion, and amortization	(921,696,714)	(755,699,056)
	1,483,312,165	1,079,033,739
Other Assets:		
Debt issuance costs	7,382,265	8,026,780
Restricted assets	2,414,287	2,296,968
	9,796,552	10,323,748
	$ 1,585,681,758	$ 1,204,412,622
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 74,425,082	$ 51,973,004
Accrued capital costs	55,282,001	30,073,728
Accrued interest	8,764,278	8,508,196
Undistributed oil and gas revenues	7,503,927	7,866,086
Total Current Liabilities	145,975,288	98,421,014
Long-Term Debt	381,400,000	350,000,000
Deferred Income Taxes	224,966,598	129,306,891
Asset Retirement Obligation	33,694,603	19,095,368
Lease Incentive Obligation	1,728,297	271,182
Commitments and Contingencies		
Stockholders' Equity:		
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding	—	—
Common stock, $.01 par value, 85,000,000 shares authorized, 30,170,004 and 29,458,974 shares issued, and 29,742,918 and 29,009,530 shares outstanding, respectively	301,700	294,590
Additional paid-in capital	387,555,797	365,085,695
Treasury stock held, at cost, 427,086 and 449,444 shares, respectively	(6,124,944)	(6,445,586)
Unearned compensation	—	(5,849,820)
Retained earnings	415,868,097	254,302,757
Accumulated other comprehensive income (loss), net of income tax	316,322	(69,469)
	797,916,972	607,318,167
	$ 1,585,681,758	$ 1,204,412,622

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Income

Swift Energy Company and Subsidiaries

	Year Ended December 31,		
	2006	2005	2004
Revenues:			
Oil and gas sales	$ 601,551,368	$ 423,766,245	$ 311,285,172
Price-risk management and other, net	13,889,862	(539,756)	(1,008,398)
	615,441,230	423,226,489	310,276,774
Costs and Expenses:			
General and administrative, net	31,316,644	22,176,362	17,787,125
Depreciation, depletion, and amortization	169,295,774	107,477,787	81,580,828
Accretion of asset retirement obligation	1,034,322	761,042	673,654
Lease operating cost	62,474,619	47,321,841	41,214,256
Severance and other taxes	65,452,043	42,176,505	30,401,293
Interest expense, net	23,581,663	24,873,401	27,643,108
Debt retirement cost	—	—	9,536,268
	353,155,065	244,786,938	208,836,532
Income Before Income Taxes	262,286,165	178,439,551	101,440,242
Provision for Income Taxes	100,720,825	62,661,095	32,989,325
Net Income	$ 161,565,340	$ 115,778,456	$ 68,450,917
Per Share Amounts—			
Basic: Net Income	$ 5.52	$ 4.06	$ 2.46
Diluted: Net Income	$ 5.38	$ 3.95	$ 2.41
Weighted Average Shares Outstanding	29,265,366	28,496,275	27,822,413

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 Compen-sation	Retained Earnings	Accumulated Other Com-prehensive Income (Loss)	Total
Balance, December 31, 2003	$ 280,111	$ 334,865,204	$ (7,558,093)	$ —	$ 70,073,384	$ (269,342)	$ 397,391,264
Stock issued for benefit plans (46,150 shares)	—	166,298	661,848	—	—	—	828,146
Stock options exercised (509,105 shares)	5,091	4,260,882	—	—	—	—	4,265,973
Tax benefits from exercise of stock options	—	1,956,555	—	—	—	—	1,956,555
Employee stock purchase plan (50,418 shares)	504	502,097	—	—	—	—	502,601
Grants of restricted stock (100,900 shares)	—	1,785,262	—	(1,785,262)	—	—	—
Amortization of restricted stock compensation	—	—	—	56,677	—	—	56,677
Comprehensive income:							
Net income	—	—	—	—	68,450,917	—	68,450,917
Change in fair value of other comprehensive income	—	—	—	—	—	720,007	720,007
Total comprehensive income	—	—	—	—	—	—	69,170,924
Balance, December 31, 2004	$ 285,706	$ 343,536,298	$ (6,896,245)	$ (1,728,585)	$ 138,524,301	$ 450,665	$ 474,172,140
Stock issued for benefit plans (31,424 shares)	—	435,134	450,659	—	—	—	885,793
Stock options exercised (840,847 shares)	8,409	9,804,555	—	—	—	—	9,812,964
Tax benefits from exercise of stock options	—	4,366,236	—	—	—	—	4,366,236
Employee stock purchase plan (32,495 shares)	325	642,354	—	—	—	—	642,679
Issuance of restricted stock (15,000 shares)	150	—	—	—	—	—	150
Grants of restricted stock (158,500 shares)	—	6,668,608	—	(6,072,008)	—	—	596,600
Forfeitures of restricted stock	—	(367,490)	—	367,490	—	—	—
Amortization of restricted stock compensation	—	—	—	1,583,283	—	—	1,583,283
Comprehensive income:							
Net income	—	—	—	—	115,778,456	—	115,778,456
Change in fair value of other comprehensive loss	—	—	—	—	—	(520,134)	(520,134)
Total comprehensive income	—	—	—	—	—	—	115,258,322
Balance, December 31, 2005	$ 294,590	$ 365,085,695	$ (6,445,586)	$ (5,849,820)	$ 254,302,757	$ (69,469)	$ 607,318,167
Stock issued for benefit plans (22,358 shares)	—	714,049	320,642	—	—	—	1,034,691
Stock options exercised (652,829 shares)	6,528	11,830,763	—	—	—	—	11,837,291
Adoption of SFAS No. 123R	—	(5,875,280)	—	5,849,820	—	—	(25,460)
Excess tax benefits from stock-based awards	—	4,811,362	—	—	—	—	4,811,362
Employee stock purchase plan (22,425 shares)	224	671,106	—	—	—	—	671,330
Issuance of restricted stock (35,776 shares)	358	(358)	—	—	—	—	—
Amortization of stock compensation	—	10,318,460	—	—	—	—	10,318,460
Comprehensive income:							
Net income	—	—	—	—	161,565,340	—	161,565,340
Other comprehensive income	—	—	—	—	—	385,791	385,791
Total comprehensive income	—	—	—	—	—	—	161,951,131
Balance, December 31, 2006	$ 301,700	$ 387,555,797	$ (6,124,944)	$ —	$ 415,868,097	$ 316,322	$ 797,916,972

[1] $.01 par value.

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Cash Flows

Swift Energy Company and Subsidiaries

	Year Ended December 31, 2006	2005	2004
Cash Flows from Operating Activities:			
Net income	$ 161,565,340	$ 115,778,456	$ 68,450,917
Adjustments to reconcile net income to net cash provided by operating activities—			
Depreciation, depletion, and amortization	169,295,774	107,477,787	81,580,828
Accretion of asset retirement obligation	1,034,322	761,042	673,654
Deferred income taxes	90,027,972	61,911,095	32,513,325
Stock-based compensation expense	6,905,260	1,450,600	57,709
Debt retirement cost – cash and non-cash	—	—	9,536,268
Other	3,225,561	362,013	(357,164)
Change in assets and liabilities—			
Increase in accounts receivable	(19,178,818)	(6,778,383)	(11,040,543)
Increase in accounts payable and accrued liabilities	10,905,914	5,071,870	843,341
Increase (decrease) in income taxes payable	883,639	—	(135,984)
Increase (decrease) in accrued interest	256,082	(700,996)	460,536
Net Cash Provided by Operating Activities	424,921,046	285,333,484	182,582,887
Cash Flows from Investing Activities:			
Additions to property and equipment	(363,222,113)	(235,547,815)	(171,095,101)
Proceeds from the sale of property and equipment	24,678,020	7,296,833	5,058,147
Acquisition of properties	(194,269,399)	(28,927,091)	(27,196,336)
Net cash received as operator of oil and gas properties	9,385,700	17,797,022	3,921,673
Net cash received (distributed) as operator of partnerships	409,816	(948,292)	884,093
Other	(528,415)	255,189	(658,630)
Net Cash Used in Investing Activities	(523,546,391)	(240,074,154)	(189,086,154)
Cash Flows from Financing Activities:			
Proceeds from long-term debt	—	—	150,000,000
Payments of long-term debt	—	—	(125,000,000)
Net proceeds from (payments of) bank borrowings	31,400,000	(7,500,000)	(8,400,000)
Net proceeds from issuances of common stock	12,508,621	10,325,114	4,825,251
Excess tax benefits from stock-based awards	3,327,713	—	—
Payments of debt retirement costs	—	—	(6,734,611)
Payments of debt issuance costs	(557,500)	—	(4,333,535)
Net Cash Provided by Financing Activities	46,678,834	2,825,114	10,357,105
Net Increase (Decrease) in Cash and Cash Equivalents	$ (51,946,511)	$ 48,084,444	$ 3,853,838
Cash and Cash Equivalents at Beginning of Year	53,004,562	4,920,118	1,066,280
Cash and Cash Equivalents at End of Year	$ 1,058,051	$ 53,004,562	$ 4,920,118
Supplemental Disclosures of Cash Flows Information:			
Cash paid during year for interest, net of amounts capitalized	$ 22,690,797	$ 24,482,934	$ 26,064,158
Cash paid during year for income taxes	$ 9,779,500	$ 750,000	$ 476,000

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 Tax Value
Other comprehensive loss at December 31, 2005	$ (110,094)	$ 40,625	$ (69,469)
Change in fair value of cash flow hedges	4,672,043	(1,733,328)	2,938,715
Effect of cash flow hedges settled during the period	(4,059,052)	1,506,128	(2,552,924)
Other comprehensive income at December 31, 2006	$ 502,897	$ (186,575)	$ 316,322

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	$68,450,917
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(2,712,441)	(3,557,541)
	Pro Forma	$113,066,015	$64,893,376
Basic EPS:	As Reported	$4.06	$2.46
	Pro Forma	$3.97	$2.33
Diluted EPS:	As Reported	$3.95	$2.41
	Pro Forma	$3.86	$2.29

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			2004		
	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:									
Net Income and Share Amounts	$161,565,340	29,265,366	$5.52	$115,778,456	28,496,275	$4.06	$68,450,917	27,822,413	$2.46
Dilutive Securities:									
Restricted Stock	—	168,759		—	61,516		—	—	
Stock Options	—	581,891		—	736,937		—	524,860	
Diluted EPS:									
Net Income and Assumed Share Conversions	$161,565,340	30,016,016	$5.38	$115,778,456	29,294,728	$3.95	$68,450,917	28,347,273	$2.41

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

Income before taxes is as follows:

	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	2004
Income taxes computed at U.S. statutory rate (35%)	$ 91,800	$ 62,454	$ 35,504
State tax provisions, net of federal benefits	3,921	2,145	1,140
Effect of foreign operations	(293)	(452)	(309)
Currency exchange impact on foreign tax calculation	(1,346)	(2,769)	(2,516)
Cumulative impact of adjustments to net state income tax rate	1,547	1,008	859
Valuation allowance	3,200	—	—
Other, net	1,892	275	(1,689)
Provision for income taxes	$ 100,721	$ 62,661	$ 32,989
Effective rate	38.4%	35.1%	32.5%

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	2005
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)	$ (3,201)
Carryover items (domestic)	(2,648)	(38,119)
Acquired deferred tax asset (foreign)	(1,204)	(2,408)
Carryover items (foreign)	(55,197)	(46,089)
Unrealized stock compensation	(2,680)	(575)
Other (domestic)	(325)	(309)
Total deferred tax assets	$ (64,256)	$ (90,701)
Non-current deferred tax liabilities:		
Domestic oil and gas exploration and development costs	$ 224,580	$ 167,088
Foreign oil and gas exploration and development costs	63,254	51,863
Other (domestic)	1,389	1,057
Total deferred tax liabilities	$ 289,223	$ 220,008
Net non-current deferred tax liabilities	$ 224,967	$ 129,307

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.

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		2004	
	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	2,118,179	$ 21.28	2,998,668	$ 18.51	3,238,611	$ 16.37
Options granted	234,110	$ 45.73	176,262	$ 35.17	415,744	$ 23.36
Options canceled	(51,739)	$ 22.25	(45,142)	$ 18.94	(64,866)	$ 21.85
Options exercised[1]	(751,410)	$ 22.02	(1,011,609)	$ 9.78	(590,821)	$ 9.83
Options outstanding, end of period	1,549,140	$ 24.59	2,118,179	$ 21.28	2,998,668	$ 18.51
Options exercisable, end of period	884,876	$ 22.60	1,085,509	$ 20.98	1,542,571	$ 17.78

[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.

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

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		2004	
	Shares	Wtd. Avg. Grant Price	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	100,900	$ 23.92
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	100,900	$ 23.92

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 thousands)	December 31, 2006				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS					
Current assets	$ —	$ 75,270	$ 17,303	$ —	$ 92,573
Property and equipment	—	1,239,722	243,590	—	1,483,312
Investment in subsidiaries (equity method)	797,917	—	590,720	(1,388,637)	—
Other assets	—	42,519	705	(33,427)	9,797
Total assets	$ 797,917	$ 1,357,511	$ 852,318	$(1,422,064)	$ 1,585,682
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities	$ —	$ 137,016	$ 8,959	$ —	$ 145,975
Long-term liabilities	—	629,775	45,442	(33,427)	641,789
Stockholders' equity	797,917	590,720	797,917	(1,388,637)	797,917
Total liabilities and stockholders' equity	$ 797,917	$ 1,357,511	$ 852,318	$(1,422,064)	$ 1,585,682

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

(in thousands)	December 31, 2004			
	Swift Energy Co. (Parent and Issuer)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
ASSETS				
Current assets	$ 38,713	$ 15,673	$ —	$ 54,386
Property and equipment	719,209	204,229	—	923,438
Investment in subsidiaries (equity method)	104,003	—	(104,003)	—
Other assets	116,537	2,364	(106,152)	12,749
Total assets	$ 978,462	$ 222,265	$ (210,155)	$ 990,573
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities	$ 60,160	$ 8,458	$ —	$ 68,618
Long-term liabilities	444,130	109,805	(106,152)	447,783
Stockholders' equity	474,172	104,003	(104,003)	474,172
Total liabilities and stockholders' equity	$ 978,462	$ 222,265	$ (210,155)	$ 990,573

Condensed Consolidating Statements of Income

(in thousands)	Year Ended December 31, 2006				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Revenues	$ —	$ 550,540	$ 64,901	$ —	$ 615,441
Expenses	—	302,232	50,923	—	353,155
Income (loss) before the following:	—	248,308	13,978	—	262,286
Equity in net earnings of subsidiaries	161,565	—	151,075	(312,640)	—
Income before income taxes	161,565	248,308	165,052	(312,640)	262,286
Income tax provision (benefit)	—	97,234	3,487	—	100,721
Net income	$ 161,565	$ 151,074	$ 161,565	$ (312,640)	$ 161,565

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

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

Condensed Consolidating Statements of Cash Flows

(in thousands)	Year Ended December 31, 2006				
	Swift Energy Co. (Parent and Co-obligor)	Swift Energy Operating, LLC (Co-obligor)	Other Subsidiaries	Eliminations	Swift Energy Co. Consolidated
Cash flow from operations	$ —	$ 383,241	$ 41,680	$ —	$ 424,921
Cash flow from investing activities	—	(474,781)	(59,881)	11,115	(523,546)
Cash flow from financing activities	—	46,679	11,115	(11,115)	46,679
Net decrease in cash	—	(44,861)	(7,086)	—	(51,947)
Cash, beginning of period	—	44,911	8,094	—	53,005
Cash, end of period	$ —	$ 50	$ 1,008	$ —	$ 1,058

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

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

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	New Zealand
December 31, 2006:			
Proved oil and gas properties	$ 2,264,831,638	$ 1,932,336,298	$ 332,495,340
Unproved oil and gas properties	112,136,836	95,569,089	16,567,747
	2,376,968,474	2,027,905,387	349,063,087
Accumulated depreciation, depletion, and amortization	(915,397,437)	(808,708,770)	(106,688,667)
Net capitalized costs	$ 1,461,571,037	$ 1,219,196,617	$ 242,374,420
December 31, 2005:			
Proved oil and gas properties	$ 1,731,866,298	$ 1,468,981,981	$ 262,884,317
Unproved oil and gas properties	87,553,220	58,196,531	29,356,689
	1,819,419,518	1,527,178,512	292,241,006
Accumulated depreciation, depletion, and amortization	(748,327,443)	(671,117,089)	(77,210,354)
Net capitalized costs	$ 1,071,092,075	$ 856,061,423	$ 215,030,652

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, 2006		
	Total	Domestic	New Zealand
Acquisition of proved and unproved properties	$212,499,280	$212,499,280	$ —
Lease acquisitions and prospect costs[1]	79,183,368	68,594,051	10,589,317
Exploration	29,285,958	13,224,894	16,061,064
Development[2]	261,142,220	231,085,290	30,056,930
Total acquisition, exploration, and development[3,4]	$582,110,826	$525,403,515	$ 56,707,311

	Year Ended December 31, 2005		
	Total	Domestic	New Zealand
Acquisition of proved and unproved properties	$ 31,429,343	$ 31,429,343	$ —
Lease acquisitions and prospect costs[1]	41,397,277	34,502,163	6,895,114
Exploration	52,350,339	38,424,995	13,925,344
Development[2]	141,081,231	111,057,945	30,023,286
Total acquisition, exploration, and development[3,4]	$266,258,190	$215,414,446	$ 50,843,744

	Year Ended December 31, 2004		
	Total	Domestic	New Zealand
Acquisition of proved and unproved properties	$ 31,771,094	$ 31,771,094	$ —
Lease acquisitions and prospect costs[1]	34,545,393	27,713,059	6,832,334
Exploration	17,430,265	16,714,982	715,283
Development[2]	108,259,091	79,338,697	28,920,394
Total acquisition, exploration, and development[3,4]	$192,005,843	$155,537,832	$ 36,468,011

[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 Zealand
Oil and gas sales	$ 601,551,368	$ 537,512,509	$ 64,038,859
Lease operating cost	(62,474,619)	(49,948,039)	(12,526,580)
Severance and other taxes	(65,452,043)	(61,234,906)	(4,217,137)
Depreciation, depletion, and amortization	(166,518,190)	(136,826,013)	(29,692,177)
Accretion of asset retirement obligation	(1,034,322)	(884,105)	(150,217)
	306,072,194	288,619,446	17,452,748
Provision for income taxes	117,531,722	110,829,867	6,701,855
Results of producing activities	$ 188,540,472	$ 177,789,579	$ 10,750,893
Amortization per physical unit of production (equivalent Mcf of gas)	$ 2.37	$ 2.41	$ 2.20

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

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

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		New Zealand	
	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)	Natural Gas (Mcf)	Oil, NGL, and Condensate (Bbls)
Proved reserves as of December 31, 2003	335,804,862	80,759,903	242,321,275	67,015,693	93,483,587	13,744,210
Revisions of previous estimates[1]	(3,306,705)	(1,117,715)	(1,619,531)	695,274	(1,687,174)	(1,812,989)
Purchases of minerals in place	9,808,953	5,602,508	9,808,953	5,602,508	—	—
Sales of minerals in place	(2,524,760)	(44,803)	(2,524,760)	(44,803)	—	—
Extensions, discoveries, and other additions	2,205,670	830,111	2,205,670	830,111	—	—
Production	(23,741,726)	(5,762,796)	(12,299,772)	(4,959,740)	(11,441,954)	(803,056)
Proved reserves as of December 31, 2004	318,246,294	80,267,208	237,891,835	69,139,043	80,354,459	11,128,165
Revisions of previous estimates[1]	(21,461,605)	(2,199,673)	(13,751,124)	(1,023,808)	(7,710,481)	(1,175,866)
Purchases of minerals in place	9,336,088	3,262,761	9,336,088	3,262,761	—	—
Sales of minerals in place	(3,737,714)	(100,121)	(3,737,714)	(100,121)	—	—
Extensions, discoveries, and other additions	8,699,329	3,819,595	7,275,207	3,722,744	1,424,122	96,851
Production	(23,609,242)	(5,996,714)	(11,739,485)	(5,217,343)	(11,869,757)	(779,371)
Proved reserves as of December 31, 2005	287,473,150	79,053,056	225,274,807	69,783,276	62,198,343	9,269,779
Revisions of previous estimates[1]	(33,631,025)	3,127,635	(34,542,219)	3,135,885	911,194	(8,250)
Purchases of minerals in place	60,187,095	2,922,553	60,187,095	2,922,553	—	—
Sales of minerals in place	(6,122,283)	(708,691)	(6,122,283)	(708,691)	—	—
Extensions, discoveries, and other additions	39,012,428	5,627,297	38,466,980	5,512,795	545,448	114,502
Production	(22,787,948)	(7,902,766)	(13,603,589)	(7,181,287)	(9,184,359)	(721,479)
Proved reserves as of December 31, 2006	324,131,417	82,119,084	269,660,791	73,464,531	54,470,626	8,654,552
Proved developed reserves:[2]						
December 31, 2003	210,119,927	45,525,366	138,173,341	38,767,983	71,946,586	6,757,383
December 31, 2004	193,310,761	42,037,852	140,549,052	36,628,873	52,761,709	5,408,979
December 31, 2005	152,001,133	37,989,821	125,367,690	35,298,324	26,633,443	2,691,497
December 31, 2006	151,276,834	34,956,469	133,815,108	33,345,567	17,461,726	1,610,902

[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 net cash flows relating to proved oil and gas reserves is as follows:

	Year Ended December 31, 2006		
	Total	Domestic	New Zealand
Future gross revenues	$ 6,341,394,321	$ 5,659,084,913	$ 682,309,408
Future production costs	(1,393,634,094)	(1,167,117,123)	(226,516,971)
Future development costs	(935,003,617)	(886,842,793)	(48,160,824)
Future net cash flows before income taxes	4,012,756,610	3,605,124,997	407,631,613
Future income taxes	(1,187,858,603)	(1,137,617,295)	(50,241,308)
Future net cash flows after income taxes	2,824,898,007	2,467,507,702	357,390,305
Discount at 10% per annum	(956,238,277)	(835,593,066)	(120,645,211)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,868,659,730	$ 1,631,914,636	$ 236,745,094

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

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

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	2004
Beginning balance	$ 2,159,369,463	$ 1,464,945,495	$ 1,134,856,535
Revisions to reserves proved in prior years—			
Net changes in prices and production costs	(658,283,413)	1,232,876,998	398,333,372
Net changes in future development costs	(166,890,534)	(173,219,347)	(117,672,270)
Net changes due to revisions in quantity estimates	(60,713,716)	(138,969,442)	(12,754,357)
Accretion of discount	314,344,631	199,799,374	152,715,946
Other	(98,478,730)	17,191,849	49,111,385
Total revisions	(670,021,762)	1,137,679,432	469,734,076
New field discoveries and extensions, net of future production and development costs	212,629,383	152,461,162	30,609,517
Purchases of minerals in place	289,338,576	99,129,117	118,575,886
Sales of minerals in place	(20,378,583)	(10,164,069)	(7,339,601)
Sales of oil and gas produced, net of production costs	(473,624,706)	(334,267,899)	(239,669,623)
Previously estimated development costs incurred	187,133,510	100,614,837	98,924,021
Net change in income taxes	184,213,849	(451,028,612)	(140,745,316)
Net change in standardized measure of discounted future net cash flows	(290,709,733)	694,423,968	330,088,960
Ending balance	$ 1,868,659,730	$ 2,159,369,463	$ 1,464,945,495

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.

Form 10-K Excerpts

Item 1. Business

See pages 77 and 78 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 3,000 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 licenses, 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 December 31, 2006		
	Total	Domestic	New Zealand
Estimated Proved Oil and Natural Gas Reserves			
Natural gas reserves (MMcf):			
Proved developed	151,276	133,815	17,462
Proved undeveloped	172,855	135,846	37,009
Total	324,131	269,661	54,471
Oil reserves (MBbl):			
Proved developed	34,956	33,346	1,611
Proved undeveloped	47,163	40,119	7,044
Total	82,119	73,465	8,655
Total Estimated Reserves (Bcfe)	817	710	107
Estimated Discounted Present Value of Proved Reserves (in millions)			
Proved developed	$ 1,382	$ 1,307	$ 75
Proved undeveloped	1,326	1,137	189
PV-10 Value	$ 2,708	$ 2,444	$ 264

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

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

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

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

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

	As of December 31, 2006		
(In millions)	Total	Domestic	New Zealand
PV-10 Value	$ 2,708	$ 2,444	$ 264
Future income taxes (discounted at 10%)	(800)	(778)	(22)
Asset retirement obligations (discounted at 10%)	(39)	(34)	(5)
Standardized Measure of Discounted Future Net Cash Flows Relating to Oil and Gas Reserves	$ 1,869	$ 1,632	$ 237

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

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

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)	% of PUD PV-10 Value
2006	111.9	25%	$ 315.9	24%
2005	110.6	24%	406.5	31%
2004	58.4	13%	189.9	14%
2003	51.4	11%	171.4	13%
2002	40.3	9%	91.6	7%
Prior to 2002	83.2	18%	151.2	11%
Total	455.8	100%	$ 1,326.5	100%

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[1]	
	Gross	Net	Gross	Net
Alabama	9,045	2,588	124	80
Alaska	—	—	45,301	15,994
Louisiana	126,472	106,133	48,376	43,464
Texas	129,997	90,165	18,271	13,239
Wyoming	640	151	35,771	33,975
All other states	320	266	400	258
Offshore Louisiana	4,609	277	5,000	258
Total Domestic	271,083	199,580	153,243	107,268
New Zealand	9,960	9,912	304,400	172,469
Total	281,043	209,492	457,643	279,737

[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:

		Gross Wells			Net Wells		
Year	Type of Well	Total	Producing	Dry	Total	Producing	Dry
2006	Exploratory–Domestic	6	—	6	5.5	—	5.5
	Development–Domestic	49	42	7	47.6	40.6	7.0
	Exploratory–New Zealand	4	—	4	4.0	—	4.0
	Development–New Zealand	4	3	1	4.0	3.0	1.0
2005	Exploratory–Domestic	9	5	4	9.0	5.0	4.0
	Development–Domestic	45	37	8	44.3	36.3	8.0
	Exploratory–New Zealand	5	1	4	3.7	1.0	2.7
	Development–New Zealand	5	2	3	5.0	2.0	3.0
2004	Exploratory–Domestic	10	4	6	7.5	2.3	5.2
	Development–Domestic	44	37	7	41.7	35.0	6.7
	Exploratory–New Zealand	1	—	1	1.0	—	1.0
	Development–New Zealand	11	10	1	11.0	10.0	1.0

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

[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. 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.

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.

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.

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.

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*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.

NOTICE

Those portions (other than Items 10-14 incorporated by reference to Swift's proxy statement for its 2006 Annual Meeting of Shareholders) of the Form 10-K Report for the year ended December 31, 2006, not included in this Annual Report to Shareholders (including certain portions of Item 1–Business pertaining to "Competition," "Regulations," "Federal Leases," "Facilities," "Litigation," Item 1A–Risk Factors, Item 3–Legal Proceedings, Item 4–Submission of Matters to a Vote of Security Holders, Item 5–Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities pertaining to "Equity Compensation Plan Information," Item 9–Changes in and Disagreements with Accountants on Accounting and Financial Disclosure, Item 9a–Controls and Procedures, Item 9b–Other Information, and Item 15–Exhibits, Financial Statement Schedules, and Reports on Form 8-K), with no disclosures having been made as to Item 4, will be provided without charge to shareholders making a written request to Scott Espenshade, Director of Corporate Development and Investor Relations, Swift Energy Company, 16825 Northchase Drive, Suite 400, Houston, Texas 77060. Exhibits filed as part of the Form 10-K will be provided to shareholders making a written request as set forth above at a reasonable charge sufficient to cover the Company's cost in providing such exhibits.

NYSE Listing Standards

During 2006, our Chief Executive Officer certified to the New York Stock Exchange (NYSE) that he is not aware of any violation by the Company of the NYSE's corporate governance listing standards. The certifications pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 for the year ended December 31, 2006, by our Chief Executive Officer and Chief Financial Officer were included as exhibits to Swift Energy Company, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2006, which was filed with the Securities and Exchange Commission.

INVESTOR INFORMATION

BOARD OF DIRECTORS

Terry E. Swift
Chairman of the Board,
Swift Energy Company

Bruce H. Vincent
President,
Swift Energy Company

Raymond E. Galvin
Vice Chairman of the Board,
Retired President,
Chevron U.S.A. Production Company

Deanna L. Cannon
Partner, Corporate Finance Associates of
Northern Michigan

Douglas J. Lanier
Retired Vice President,
Gulf of Mexico Business Unit,
ChevronTexaco Exploration &
Production Company

Greg Matiuk
Retired Executive Vice President,
Administrative & Corporate Services,
ChevronTexaco Corporation

Henry C. Montgomery
Chairman & Founder,
Montgomery Professional
Services Corp.

Clyde W. Smith, Jr.
President,
Ascentron, Inc.

Charles J. Swindells
Managing Director of
U.S. Trust Company, N.A.

Raymond O. Loen
Director Emeritus

Virgil N. Swift
Director Emeritus

OFFICERS

Terry E. Swift
Chief Executive Officer

Bruce H. Vincent
President

Joseph A. D'Amico
Executive Vice President &
Chief Operating Officer

Alton D. Heckaman, Jr.
Executive Vice President &
Chief Financial Officer

James M. Kitterman
Senior Vice President–Operations

James P. Mitchell
Senior Vice President–Commercial
Transactions & Land

Victor R. Moran
Senior Vice President &
Chief Compliance Officer

Robert J. Banks
Vice President–International
Operations & Strategic Ventures

David P. Coatney
Vice President–Production Operations

Edward A. Duncan
Vice President–Exploration

D. Gregg Jones
Vice President–Corporate Administration

Thomas E. Schmidt
Vice President–Exploitation & Development

Tara L. Seaman
Vice President–Reserves & Evaluations

Laurent A. Baillargeon
Chief General Counsel

Karen M. Bryant
General Counsel–Corporate,
Chief Governance Officer & Secretary

Adrian D. Shelley
Treasurer

David W. Wesson
Controller

CORPORATE HEADQUARTERS

Swift Energy Company
16825 Northchase Drive, Suite 400
Houston, Texas 77060
Telephones: (281) 874-2700
(800) 777-2412

PRINCIPAL SUBSIDIARY COMPANIES

Swift Energy Operating, LLC
Houston, Texas

Swift Energy International, Inc.
Houston, Texas

Swift Energy New Zealand, Ltd.
Wellington, New Zealand

TRANSFER AGENT AND REGISTRAR

American Stock Transfer
& Trust Company
59 Maiden Lane
Plaza Level
New York, New York 10038

EXCHANGE LISTING

New York Stock Exchange, Inc.
Symbol "SFY"

INDEPENDENT ACCOUNTANTS

Ernst & Young LLP
1401 McKinney, Suite 1200
Houston, Texas 77010

COUNSEL

Baker & Hostetler, LLP
1000 Louisiana, Suite 2000
Houston, Texas 77002

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 252 stockholders of record as of December 31, 2006.

Annual Meeting

4 p.m., Tuesday, May 8, 2007
The Wyndham Greenspoint Hotel
12400 Greenspoint Dr.
Houston, Texas 77060

A. Earl Swift
1933–2006

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