SWIFT ENERGY COMPANY
2002 ANNUAL REPORT

SWIFT ENERGY HIGHLIGHTS

	2002	2001	Percent Change
Revenues	$149,969,811	$183,807,490	(18)%
Oil and Gas Sales	$141,195,713	$181,184,635	(22)%
Costs & Expenses			
(excluding the 2001 write-down of oil & gas properties)	$131,561,522	$119,137,576	10%
Write-down of Oil and Gas Properties	—	$98,862,247	—
Total Costs & Expenses	$131,561,522	$217,999,823	(40)%
Net Income	$11,923,227	$(22,347,765)	—
Earnings per Share–Basic	$0.45	$(0.90)	—
Earnings per Share–Diluted	$0.45	$(0.90)	—
Total Assets	$767,005,859	$671,684,833	14%
Working Capital	$(17,115,985)	$(36,492,355)	53%
Current Ratio	.63	.50	26%
Long-Term Debt	$324,271,973	$258,197,128	26%
Stockholders' Equity	$365,073,184	$312,652,720	17%
Long-Term Debt to Equity Ratio	.89	.83	7%
Return on Assets (net income / average assets)	2%	(4)%	—
Return on Stockholders' Equity (net income / average equity)	4%	(7)%	—
Net Cash Provided by Operating Activities	$71,626,314	$139,884,255	(49)%
Natural Gas Production (Mcf)	27,131,578	26,458,958	3%
Oil, NGL, & Condensate Production (Bbls)	3,770,128	3,055,373	23%
Total Production (Mcfe)	49,752,346	44,791,202	11%
Average Natural Gas Prices Received ($/Mcf)	$2.30	$4.23	(46)%
Average Oil, NGL, & Condensate Prices Received ($/Bbl)	$20.88	$22.64	(8)%
Average Composite Prices Received ($/Mcfe)	$2.84	$4.05	(30)%
Proved Natural Gas Reserves (Mcf)	326,731,672	324,912,125	1%
Proved Oil & Condensate Reserves (Bbls)	52,446,486	37,678,580	39%
Proved Natural Gas Liquids Reserves (Bbls)	17,992,477	15,804,056	14%
Total Proved Reserves (Mcfe)	749,365,449	645,807,939	16%
Weighted Average Shares Outstanding	26,382,906	24,732,099	7%
Year-End Shares Outstanding	27,201,509	24,795,564	10%
Number of Shareholders of Record	366	383	(4)%
Number of Shareholders in Street Name	6,980	7,690	(9)%
Market Price of Common Stock at Year-End	$9.67	$20.20	(52)%
Number of Employees	234	209	12%

See page 32 regarding the forward-looking statements in this report.
See page 63 for a glossary of abbreviations and terms.

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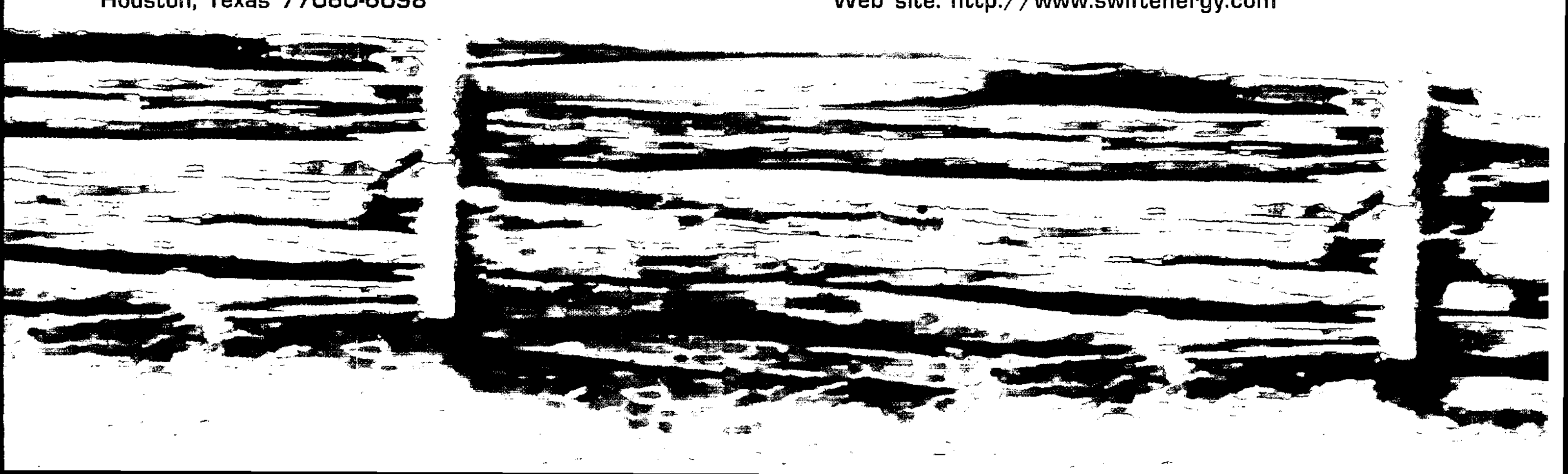

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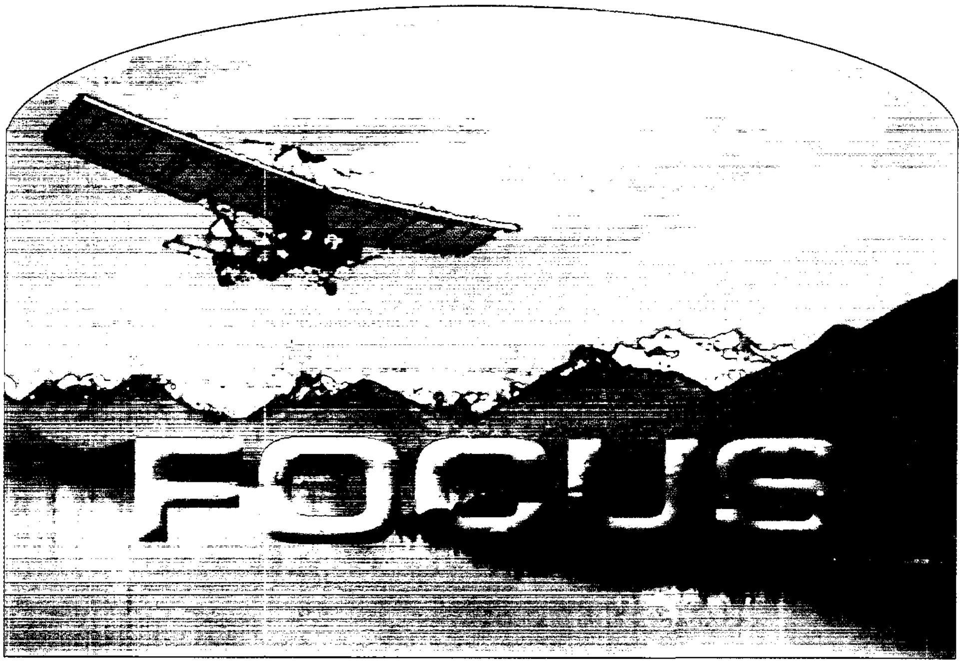
Internet Access

Additional information about Swift Energy Company is available on the Internet at http://www.swiftenergy.com. The data include press releases, Swift's annual reports on Form 10-K, quarterly reports on Form 10-Q, and current reports on Form 8-K, all available free of charge and updated as reasonably practicable after filing with the SEC. The site also includes a variety of other information. Visitors to swiftenergy.com can register to receive periodic e-mail updates concerning new information available at the web site.

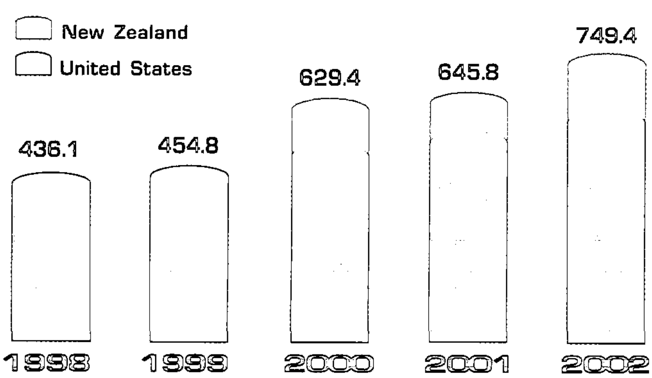


Swift focuses on building shareholder value by increasing the volume and value of its proved oil and gas reserves.

Company Profile

Swift Energy Company is an independent oil and natural gas company engaged in the development, exploration, acquisition, and operation of oil and gas properties, with a focus in the United States on onshore and inland water areas of the Texas and Louisiana Gulf Coast and in New Zealand on onshore areas of the Taranaki Basin.

Year-End Proved Reserves (Bcfe)



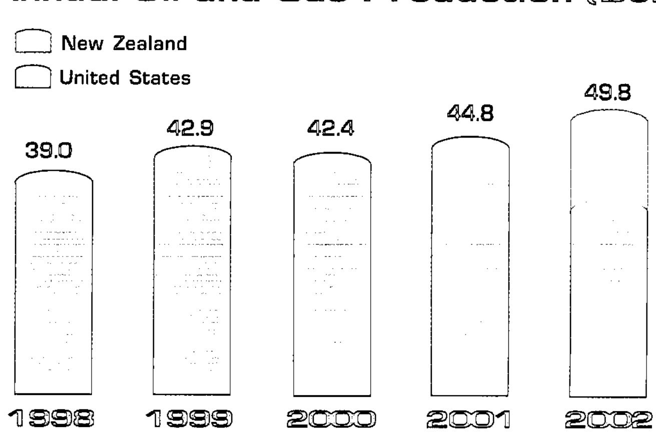
MISSION AND GOALS. As a natural resource company, Swift Energy's mission has always been to achieve efficient, sustained growth in the volume and net present value of its proved reserves. The underlying premise is that reserves growth leads to increases in oil and gas production and sales, which in turn lead to higher cash flows and earnings and ultimately to increases in shareholder value. During 2002, Swift increased its year-end proved reserves by 16% from the previous year to 749.4 billion cubic feet equivalent (Bcfe), replacing 308% of its 2002 production with a reserves replacement cost of $0.96 per thousand cubic feet equivalent (Mcfe).

Over the last five years, the Company has achieved an average compounded growth rate in proved oil and gas reserves of approximately 16% per year. Swift's success in sustaining reserves growth in a volatile pricing environment has enabled it to achieve five-year compounded growth rates of approximately 14% per year in production, 15% per year in oil and gas sales, and 5% per year in cash flows from operating activities. Swift's primary goals for 2003 are to increase both its proved oil and gas reserves and its production by 7% to 12%.

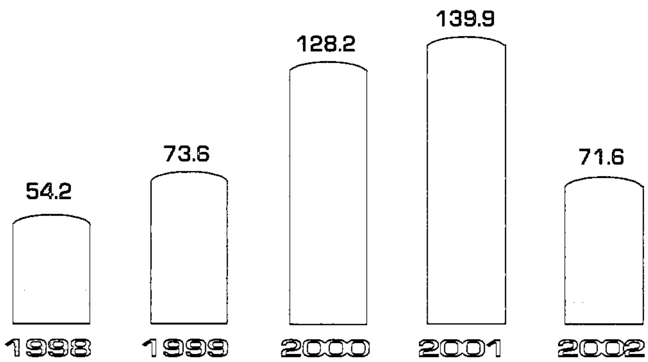
BUSINESS STRATEGY. Swift's reserves growth is primarily accomplished through a mix of exploratory and development drilling and producing property acquisitions. The specific mix of drilling and acquisitions is continually adjusted in response to changing industry conditions. In all its activities, the Company focuses on adding value through a balanced portfolio of oil and gas properties with diversified production profiles and an assortment of drilling opportunities covering a range of risks and potential rewards.

Development drilling is generally focused in the Company's core areas of operation. Domestically, these include the Lake Washington Area and Masters Creek Area in Louisiana and the AWP Olmos Area and Brookeland Area in

Annual Oil and Gas Production (Bcfe)



Net Cash Provided by Operating Activities ($ Million)



Texas. In New Zealand, they include the Rimu/Kauri Area and the TAWN Area. Exploratory drilling is conducted both in these core areas and in other regions with the potential for becoming core areas of operation. In 2002, Swift focused its drilling activities in the Lake Washington Area and will continue to do so in 2003.

In its acquisitions activities, the Company continually reviews opportunities to purchase strategic producing properties where performance can be enhanced through development drilling or improved operating efficiencies. In 2002, the Company's major acquisition was the purchase of four onshore producing oil and gas fields in New Zealand, which now comprise the Company's TAWN Area. During the fourth quarter of 2002, the TAWN Area produced 4.5 Bcfe, representing over a third of the Company's production.

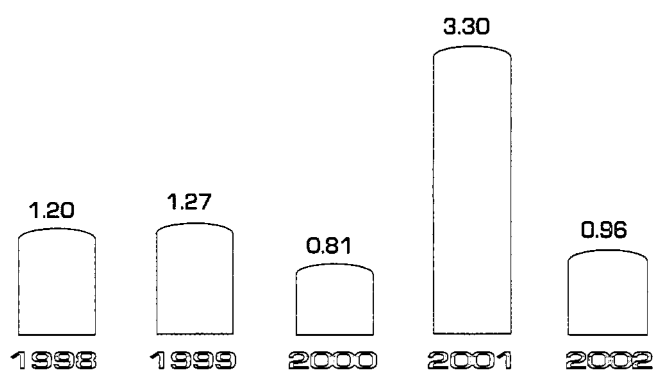
INDUSTRY ENVIRONMENT. Volatility in the prices of crude oil, natural gas, and natural gas liquids (NGLs) can have a significant impact on the revenues from Swift's operations. In 2002, the Company experienced substantially lower average domestic natural gas prices, with prices declining 29% from the previous year to $3.01 per thousand cubic feet (Mcf). Domestic crude oil prices remained relatively flat, averaging $24.57 per barrel, and domestic NGL prices averaged $13.20 per barrel in 2002, a 5% increase over the previous year's prices.

In New Zealand, the Company received an average of $24.31 per barrel for its crude oil. Natural gas sold for an average of $1.32 per Mcf under the Company's reserves-based contracts. NGL contracts averaged $11.06 per barrel. Unlike crude oil sales, which are denominated in U.S. dollars, New Zealand natural gas and NGL prices are denominated in New Zealand dollars, which significantly strengthened in relation to the U.S. dollar over the course of 2002, leading to some appreciation in New Zealand natural gas and NGL prices.

LOOKING AHEAD. In early 2002, the Company adjusted its strategy in response to a changed industry environment—characterized by lower product prices and higher service costs—that had adversely affected the Company's operations in 2001.

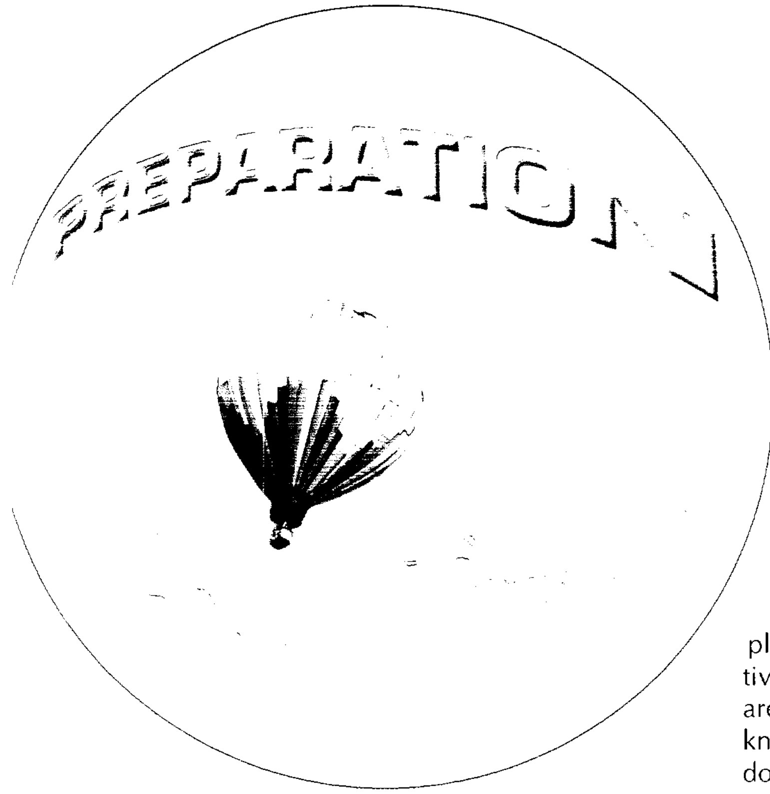
The industry environment has improved since the end of 2001, and many of the efficiency improvements, additional cost controls, and other strategic adjustments implemented in 2002 have now placed the Company in a good position to take advantage of future growth opportunities.

Reserves Replacement Costs ($ per Mcfe)



As a result of its 2002 activities, Swift has lowered its reserves replacement costs, reduced the production decline rate for its core properties, improved its financial flexibility, greatly increased its domestic production from the Lake Washington Area, initiated commercial oil and gas production in New Zealand, and retained an efficient inventory of proved undeveloped drilling locations and exploratory prospects. With these changes in place, Swift believes it is positioned to achieve significant growth in shareholder value in 2003 and beyond.

INVESTOR INFORMATION. Swift's policy is to reinvest cash flows rather than pay cash dividends in order to promote long-term growth in the value of the Company's common stock. Its common stock has been traded under the symbol "SFY" on the New York Stock Exchange (NYSE) since 1991 and on the Pacific Exchange, Inc. (PCX), since 1988.



Swift's preparation for stable growth is embedded in a strategic plan that dynamically adjusts the balance of a number of key variables in response to changes in the industry environment.

Letter to Stockholders:
Dynamic balance

At Swift Energy Company, the word "balance" is deeply ingrained in our culture. We are constantly adjusting the balance of all sorts of strategic variables. With our reserves base, we think of oil versus natural gas, developed versus undeveloped, and high initial deliverability versus long reserves life. With operations, we look at domestic versus international, exploration versus development, and acquisitions versus drilling. In finances, we consider debt versus equity, and in management, we view corporate controls versus organizational flexibility. In each case, we examine the risk versus the reward.

Early in 2002, the concept of balance took on an even deeper meaning for us, because, frankly, the profound changes that occurred in our industry the previous year temporarily pushed us off balance. Along with others in our industry, we experienced the combination of plunging product prices, soaring drilling and operating costs, and declining stock prices. To adapt to the changed environment, we had to revise our overall strategy for meeting our 2002 reserves and production goals.

Our announced targets for 2002 were a 10% to 15% increase in both our proved reserves and our production. Significant contributions to both these goals were made early in the year when we completed our acquisition of four producing properties in New Zealand just north of our Rimu/Kauri Area. Largely producing gas and known collectively as the TAWN Area, these fields accounted for over 28% of our total 2002 production and held nearly 9% of our year-end proved reserves.

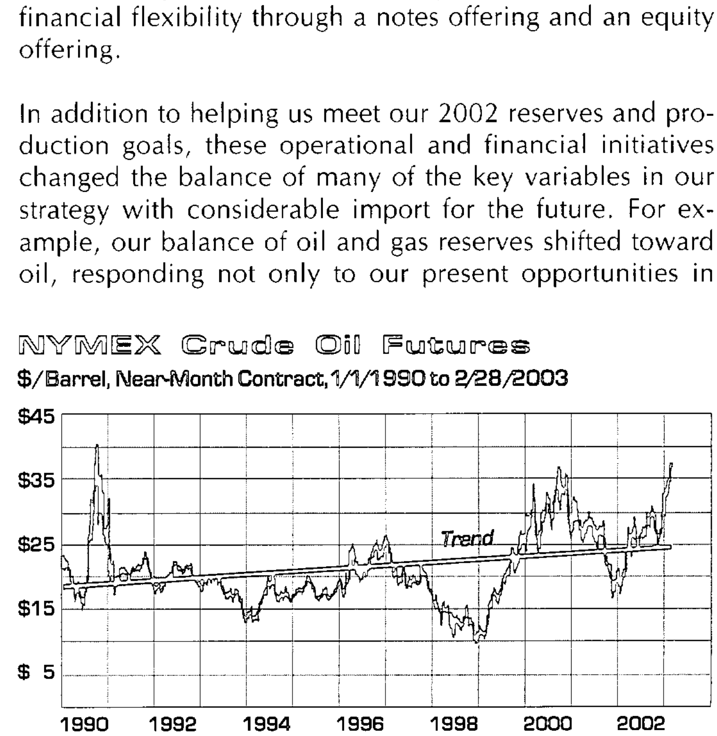
In the United States, it had been our intention to increase our 2002 reserves primarily with a diversified portfolio of drilling projects, but in the new environment it became mandatory to reduce our reserves replacement costs. This meant that we had to defer attractive but high-risk drilling projects and concentrate in an area with a mix of proven and probable reserves that were known to be long lived. The area chosen was our newest domestic core area of operation, the Lake Washington Field in Plaquemines Parish, Louisiana.

As a result of our focus in the area, Lake Washington's production more than doubled in 2002 and its proved reserves, mostly oil, increased by approximately 160%. For the Company as a whole, our year-end proven reserves increased by 16% to 749.4 Bcfe and our production increased 11% to 49.8 Bcfe, meeting or exceeding our target ranges. Moreover, these increases were accomplished with an overall reserves replacement cost of $0.96 per Mcfe, much lower than the cost experienced in 2001. Also, during the first half of the year we improved our financial flexibility through a notes offering and an equity offering.

In addition to helping us meet our 2002 reserves and production goals, these operational and financial initiatives changed the balance of many of the key variables in our strategy with considerable import for the future. For example, our balance of oil and gas reserves shifted toward oil, responding not only to our present opportunities in

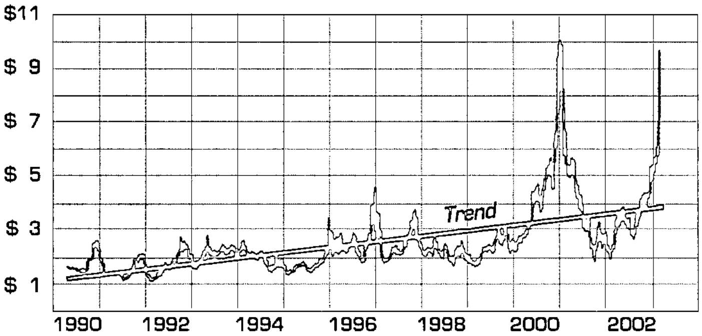
NYMEX Crude Oil Futures

$/Barrel, Near-Month Contract, 1/1/1990 to 2/28/2003



NYMEX Natural Gas Futures

$/MMBtu, Near-Month Contract, 4/3/1990 to 2/28/2003



Lake Washington but also to the current strength in crude oil prices. At the same time, our balance of developed versus undeveloped reserves moved toward developed, bringing new production on line and improving the value of our assets. We also tipped the scale away from high-deliverability assets toward properties with long-lived reserves, giving us a more stable, long-term production base.

In operations, the TAWN acquisition helped us achieve a good balance between domestic and international production and also between discovered and acquired reserves. In finances, the debt and equity offerings improved our liquidity and rebalanced our debt-to-equity profile, and in management, additional controls improved our transparency and accountability both inside and outside the organization. All this was done while maintaining the Company's flexibility, teamwork, and innovation. More fundamentally, we adopted a new, more balanced approach to risks and rewards, reflecting the current economic and industry environments.

Now that we have rebalanced these strategic variables, we are in a better position to pursue a number of exciting growth opportunities along the Texas and Louisiana Gulf Coast and in the Taranaki Basin in New Zealand. Both of these areas provide tremendous unexploited potential in a mix of geological environments, and they are both in proximity to growing markets with relatively low political risk compared to many other parts of the world. In short, they are both areas where an independent such as Swift can expand profitability for many years to come.

Domestically, we have identified 23 exploratory prospects and plan to drill four to eight of them in 2003. In New Zealand, we have analyzed four exploratory opportunities, with tentative plans to drill at least one in 2003. To reduce risk, we are seeking partners for most of these prospects.

We also intend to continue improving the value of our core properties in the United States and New Zealand through a combination of production enhancements and efficiency improvements. In the near term, the domestic driver of production growth will be the Lake Washington Field, where we plan to drill 50 to 60 development wells and two exploratory wells in 2003. Limited drilling will also be resumed in our other domestic core areas.

In the Rimu/Kauri Area in New Zealand, we have scheduled several capital projects for the first half of the year that are designed to increase the area's productivity. After realizing early last year that our drilling and completion techniques were probably damaging the producing formations, we asked an independent consultant to analyze our procedures and give us recommendations both for remediation and for future drilling. Our 2003 projects will implement those recommendations and help us to pursue the large volumes of potential reserves we still believe exist in the area.

As we review the Company's performance in 2002, it is clear that the dynamic balance of our revised strategy helped us stay the course and achieve our objectives. As a result, we have added to a strong asset base that we believe is worth substantially more than is indicated by our current stock price. We have maintained our balance through some very difficult times and are confident that we are in an excellent position to achieve stable growth in the future.

A. Earl Swift
Chairman

Terry E. Swift
President and
Chief Executive Officer

In 2002, Swift's management team made quick adjustments to its strategy in response to dramatic changes in the industry environment, positioning the Company to achieve more aggressive growth targets in 2003 and beyond.

Shareholder Value:
Balancing risk and return

Considering the inherent volatility of energy prices and their impact on stock valuations, growth in shareholder value for independent oil and gas companies should not be measured solely by short-term changes in the stock price. Over the long term, growth in shareholder value depends on sustained increases in the volume and value of the Company's proved reserves.

Over the past 22 years, from Swift's first full year of operation in 1980 through year-end 2002, Swift has achieved an annual compounded growth rate of 26% in proved reserves per share of common stock. At the end of 2002, Swift's proved reserves totaled 28 Mcfe per share, up approximately 6% per share from the previous year-end.

2002 INDUSTRY ENVIRONMENT. Achieving sustained reserves growth over the long term requires skill in balancing risk and reward in response to emerging opportunities and threats in the energy industry. In 2002, Swift's management was able to quickly adjust its plans in response to the economic and industry challenges of the previous year, when a slowdown in the U.S. economy and unforeseeable terrorist attacks jolted domestic energy markets as field service costs skyrocketed.

In 2002, domestic natural gas prices on the New York Mercantile Exchange (NYMEX) showed tremendous volatility, ranging from a low for the year of $1.91 per million British thermal units (MMBtu) on January 28 to a high for the year of $5.34 per MMBtu on December 16.

Oil prices also varied widely in 2002, with NYMEX oil futures prices increasing from a low for the year of $17.97 per barrel on January 17 to a high for the year of $32.72 on December 27, with much volatility in between.

LONG-TERM INDUSTRY OUTLOOK. Over the longer term, the outlook for both domestic and international oil and natural gas prices appears promising.

In early 2003, the world experienced relatively strong crude oil prices, driven by tensions between the United States and Iraq, the Venezuelan oil strike, and a decline in world oil inventories.

Oil prices are expected to continue undergoing significant price volatility in the years ahead, but with a trend toward strong prices as the global economy picks up speed and oil consumption levels rise in developing countries around the world.

Natural gas is expected to remain the fastest growing fossil fuel, with electricity generation continuing as the fastest growing component of natural gas demand. Given anticipated growth in natural gas consumption, supply may struggle to keep pace. Growth in Canadian imports, which supplied over half of the increase in U.S. consumption during the previous decade, is expected to slow or even decline during the next 10 years, and challenges to U.S. production became apparent in 2002, when a 2001 peak in rig rates failed to forestall production declines the very next year.

In New Zealand, natural gas is primarily produced under contractual agreements that are not subject to short-term price swings. Over the longer term, natural gas pricing trends are expected to significantly strengthen as the Maui Field nears depletion. The Maui Field, which currently supplies over 70% of the island nation's natural gas, may reach depletion as early as 2007.

With these positive long-term outlooks for oil and natural gas prices in both the United States and in New Zealand, Swift will continue to optimally balance risk and reward in its pursuit of more aggressive growth in shareholder value.

Over its 23-year history, Swift has demonstrated the stamina to persevere through volatile industry cycles. After lowering its production decline rate in 2002 and building a considerable inventory of undeveloped and potential reserves, the Company is equipped to pursue sustained growth in the years ahead.

Domestic Core Areas:
Balancing a diversified portfolio of producing properties

Early in 2002, as part of its strategy in the changed industry environment, Swift Energy limited domestic exploratory drilling for the year and directed its development drilling in the U.S. to projects with lower risk and lower costs compared to those in the previous year. In particular, drilling projects in 2002 targeted reserves with stable, long-term production, and no drilling was done in the Austin Chalk trend where the production typically declines rapidly after early payout. The strategy also called for additional scrutiny of all operational expenses to improve their cost effectiveness.

Carrying out this program was greatly facilitated by Swift's acquisition in 2001 of property in the Lake Washington Field in Plaquemines Parish, Louisiana, which met the Company's criteria for drilling in 2002 and therefore became the focus of its activities. By year-end 2002, these activities not only had added significantly to the Company's reserves base and production, but also had charted the course for an expanded domestic drilling program in 2003.

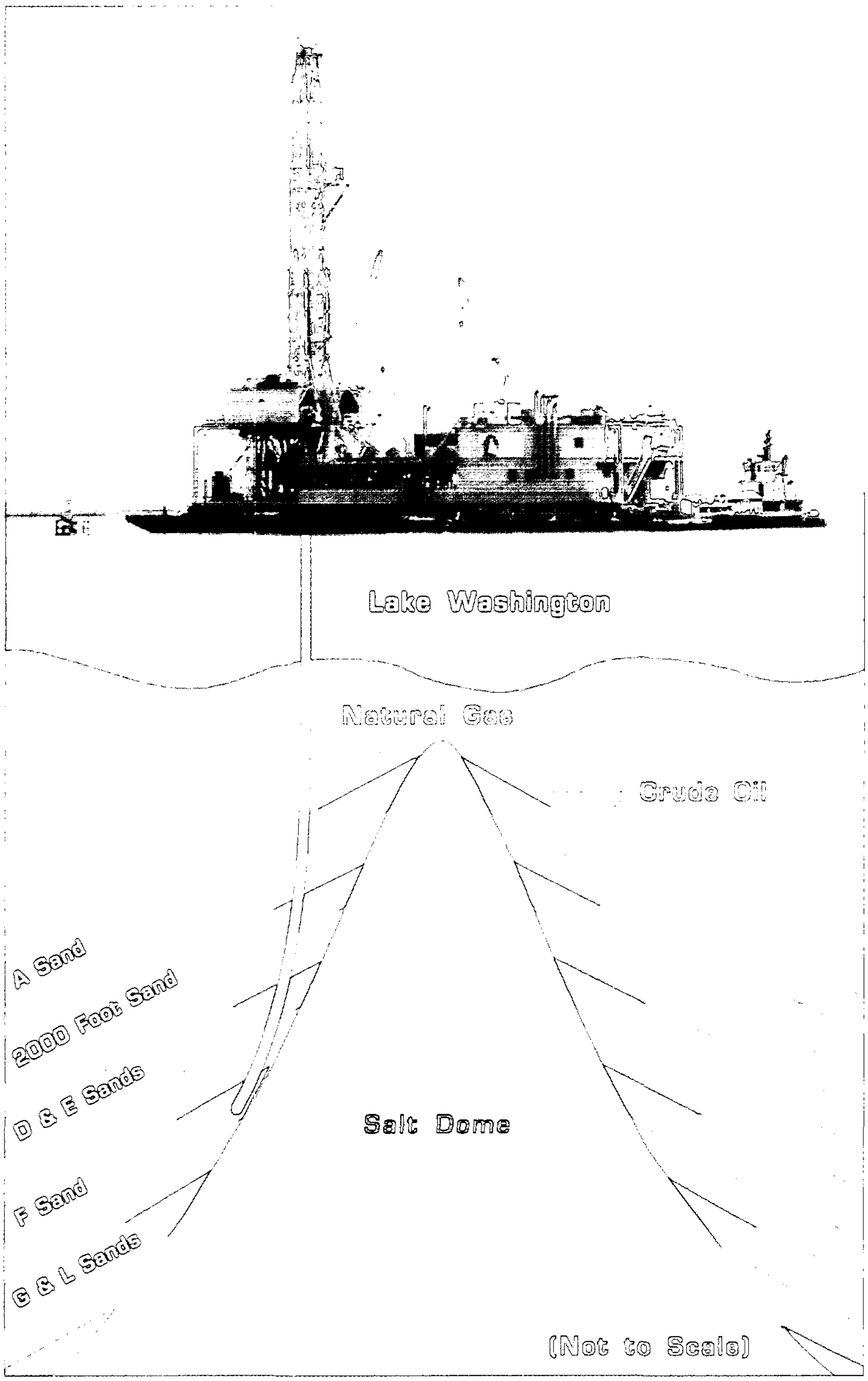
LAKE WASHINGTON AREA. Since it was acquired in March 2001, Swift Energy's Lake Washington Area has proved to have far greater potential for increased reserves and production than even the most optimistic projections made at the time of its purchase. As this became more and more apparent, Swift gradually increased its drilling activity in the Lake Washington Field in 2002 above the 20 wells originally planned. At year-end, 27 of the 30 wells drilled in the Company's domestic program were in the Lake Washington Field. These included 23 development wells with 17 successful completions and four exploratory wells with two successful completions, yielding an overall success rate of 70%. With the additional five successful wells that Swift drilled in the field late in 2001 also considered, the Company's overall success rate in Lake Washington has been 75%.

At year-end 2002, the Company's proved reserves in the Lake Washington Area, which are over 95% oil, had increased from 7.7 million barrels of oil equivalent (MMBOE) at the time of the acquisition to 31.7 MMBOE, or more than 300%. With much of the field still unexploited and approximately 65% of the proved reserves still to be developed, Swift has embarked on a multiyear drilling program in the area to develop "high-quality" reserves with production that can be sustained for years. At year-end, the Lake Washington Area held 25% of the Company's total proved reserves.

Located near the mouth of the Mississippi River, the Lake Washington Field was discovered in the 1930s but was only partially developed by a succession of operators. In 1969, it became a lake-covered field with water depths of 2 to 12 feet when Hurricane Camille collapsed a ring-shaped levee that had protected a sulfur mining operation within the area. Swift has a 100% working interest in approximately 11,000 net acres in the field, which includes an underlying salt dome structure with surface depths varying from about 1,200 feet at its peak down to about 10,000 feet over most of the acreage.

The Lake Washington Field produces from an east-west trend of Miocene age sand layers that lie one above the other around the salt dome. In general, the sand layers, some of which are up to 200 feet thick, are at their shallowest depths near the salt dome surface and slant downward with distance from the dome. The field itself is heavily faulted; that is, the sands are contained in numerous fault blocks (compartments) that can range in size from a few acres to several hundred acres. As a result, oil is trapped in isolated reservoirs surrounding the salt dome.

Before Swift became the operator of the Lake Washington Area, most of the drilling had occurred on the north and east sides of the dome. Swift began drilling in this same region but increasingly moved closer to the dome's surface to intercept the "attics" of the fault blocks, which are regions closest to the dome surface that have a higher potential for containing hydrocarbons and have been bypassed by wells drilled further out from the structure. With the move toward the dome, Swift also converted from



The Lake Washington Field produces from an east-west trend of Miocene age sand layers that lie one above the other around a salt dome. Hydrocarbon deposits (primarily oil) are found in sands contained in numerous fault blocks (compartments) surrounding the salt dome. Swift initiated the drilling of directional wells parallel to the dome's surface in order to intercept multiple sand layers in the fault blocks.*

* The above conceptual diagram does not depict all relevant geologic and engineering information.

straight-hole drilling, where the well depths are limited by the dome's salt surface, to directional drilling, where the holes are drilled parallel to the dome's surface. This enables many more sands to be encountered at much deeper depths. In some cases, the bottom of the hole may be as much as 1/2 mile away from the surface location of the rig in the horizontal direction. Directional drilling also allows sidetrack wells to be drilled from the same surface location if the targeted sand is not originally encountered, as has been done for a number of Swift's wells.

In general, the 50-plus productive sands in the Lake Washington Field are well known and identified by the alphabet or, at times, by the depths at which they were first found. When Swift began drilling in the field, it largely targeted the relatively shallow sands (typically the A through E sands at depths of 1,500 to 4,000 feet). In one well that was deviated down the north flank of the dome (the Cockrell-Moran #187), the Company was targeting the deeper H and K sands when, at a depth of 4,278 feet, it encountered a highly productive F sand that had not previously been known to contain hydrocarbons. The well is currently producing up to 1,200 BOE per day from a 179-foot thickness of this sand.

A productive F sand was also intercepted in five subsequent wells, three on the north flank of the dome and two on the southeast flank. The discovery of hydrocarbons in the F sand alone added 3.6 million BOE to Swift's proven reserves at year-end.

Later in the year, three other productive sands were discovered. One, called the "2,000-foot sand," was initially identified on the northeast flank of the dome and subsequently in two wells on the north flank. Another, called the "8,400-foot sand," was discovered in one well on the far northern flank. The third, the shallow B sand not previously known to contain hydrocarbons, was found on the south flank of the dome.

By year-end 2002, Swift had encountered 44 different pay zones in the wells it had drilled in the Lake Washington Field and had completed wells to produce from 16 of the zones with an average net pay of 140 feet of sand per completed well. The initial average production rate per well was 200 to 240 BOE per day, with each well accessing an average of approximately 345,000 BOE of unrisked reserves.

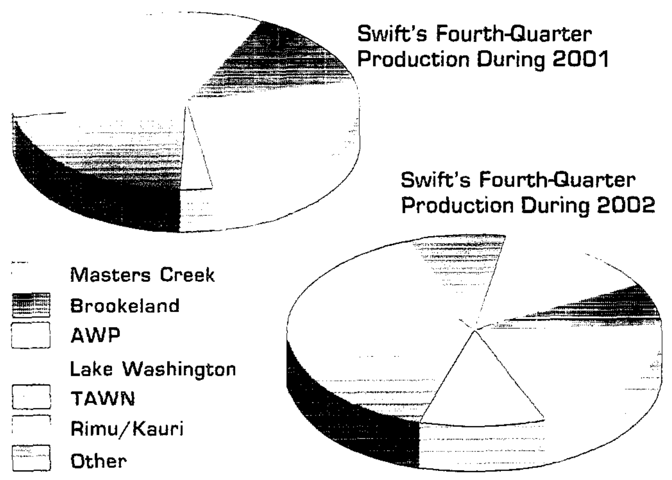
As Swift continues drilling in the Lake Washington Field, it will proceed around the salt dome. In selecting new well locations, it will look for attic locations updip from previous known production and also for untested fault blocks. It will also add wells in fault blocks that require multiple wells to drain effectively, and it will redrill wells that were prematurely abandoned by earlier operators because of mechanical problems or the unavailability of adequate completion technologies. In all cases, the dual objective is to increase both production and reserves.

Swift has already identified over 70 future drilling sites, but when one successful well is drilled in a new fault block, it can lead to 10 to 20 additional wells in the same block. The plans are to keep two drilling rigs in the field during 2003 to drill 50 to 60 development wells and two exploratory wells (see page 16). In preparation for this accelerated program, the state and federal permitting processes are well under way for a number of wells, and the field's infrastructure has undergone considerable upgrading.

The facility upgrades have been carried out on several fronts. Among the most important was the expansion of the field's processing capability from an initial 2,000 barrels of oil per day to 9,250 barrels of oil per day at year-end 2002, with plans to expand to 14,000 barrels of oil per day at year-end 2003.

Another crucial upgrade was the addition of a capability for on-site three-phase (oil-water-gas) separation of the production. When Lake Washington was acquired, only two-phase separation was possible (liquids-gas), with the liquids being sent to another company for separation and sale. In order to accomplish the three-phase separation and sell the oil directly, the Company had to rebuild a Lease Automated Custody Transfer unit (LACT unit) near an Exxon pipeline. After delays caused by Tropical Storm Isidore and Hurricane Lili, the unit was placed in operation at the end of November. A more centrally located LACT unit with automated controls will be added during 2003.

Still another important upgrade was the conversion of two older wells into salt water disposal wells. The water-driven field produces significant quantities of salt water along with the oil, and on-site separation of the liquids requires that disposal wells be available for the reinjection of the salt water. A third salt water disposal well will be added shortly.



Swift Energy diversified its 2002 production base in the United States by increasing production from the Lake Washington Area and in New Zealand by initiating commercial production in the Rimu/Kauri Area and by acquiring the TAWN Area.

Other infrastructure upgrades have included installing new gas compressors and other equipment to improve the field's gas lift system. In essentially all the wells in the field, the oil is produced with gas lift, where the gas that has been separated from the production is compressed and reinjected into the well bores to artificially lift the produced fluids.

Numerous other upgrades were related to safety and environmental issues and to the maintenance of three tank battery platforms within the lake and their associated flow lines. All of Swift's production is gathered at the three platforms, and on-going field work includes the laying of new flow lines to the platforms as new wells are completed.

As would be expected, mobility in the lake is critical. Field personnel routinely travel from place to place in boats, and the drilling rigs move within the lake on barges to drill and case each well. Completion rigs also move around on barges to perforate the well casings at the producing zones and install gravel packs around the perforations. The gravel packs, which are essential for preventing the producing zone sand from entering and clogging up the well bore, are created by displacing the smaller-grain sand near the perforations with large-grain sand that will not clog the wells and will maintain the flow of oil and gas into the well.

In order to reduce costs, the completion rig operates only when it can complete several wells at the same time with no lost time in between. Also to reduce costs over the long term, Swift simultaneously completes two zones in some wells so that the production can be switched from one zone to the other without bringing the completion rig back. This is a significant savings since a single gravel pack completion usually costs about $450,000 and two gravel pack completions can be done at the same time for about $600,000.

Even with an accelerated program in 2003, the full development of the Lake Washington Area will require several years. In 2002, its production was 740,138 BOE (4.4 Bcfe, or 8.9% of Swift's total production) and is expected to more than double in volume in 2003. With continuing increases, the Lake Washington Area is destined to become a source of stable, long-lived producing reserves for Swift for years to come.

AWP OLMOS AREA. The AWP Olmos Field in McMullen County, Texas, has been contributing to Swift Energy's production since 1989 and often is cited by Swift as a model field with long-lived reserves. At year-end 2002, Swift's interests in the field, which cover about 28,000 net acres, still accounted for 30.4% of the Company's proved reserves.

With no additional drilling in the AWP Olmos Field during 2002, the expected decline in its production was minimized by a continuing enhancement program. Typically, when a new well is completed in the tight Olmos sand (a depletion-driven reservoir), the surrounding formation is artificially fractured with a fluid pumped down the well bore and out into the formation under high pressure. The fractures then provide pathways through which the hydrocarbons can flow into the well. Over the years, the Company learned that the production of some wells can be increased by fracturing the formation around the wells a second (or third) time. By the time these refractures are carried out, production from the wells has lowered the reservoir pressure, making it possible for the second and third fractures to extend to greater distances. As a result, refracturing has become a routine enhancement procedure in the AWP Olmos Field, and the recovery factor for many regions in the field has been increased to 40% to 60%. Four refractures were performed in 2002, and eight are planned for 2003.

In the process, Swift has greatly improved its fracturing techniques and reduced fracturing costs. The original fracturing fluid consisted of massive volumes of an expensive water-based fluid (a gel) mixed with resin-coated sand, but it was gradually downsized to smaller quantities of ordinary well water and ordinary sand. During 2002, the Company began testing foam fracturing, a technique that uses a gas (either nitrogen or carbon dioxide) to comprise up to 65% of the fracturing fluid. If successful, this technique will further reduce the volumes of water mixed in with the production and will also provide additional energy needed for lifting the production.

Distribution of Swift Energy's Proved Reserves As of December 31, 2002

	Proved Reserves[a] (Bcfe)			Percent of Company's Reserves	Percent Natural Gas
	Developed	Undeveloped	Total		
Texas					
AWP Area	142.2	85.8	228.0	30.4%	65.9%
Brookeland Area	21.0	24.9	45.9	6.1%	44.7%
Other Texas	22.2	14.4	36.6	4.9%	89.8%
Total Texas	185.4	125.1	310.5	41.4%	65.6%
Louisiana					
Lake Washington Area	63.6	126.4	190.0	25.4%	1.7%
Masters Creek Area	44.9	26.2	71.1	9.5%	28.2%
Other Louisiana	0.8	–	0.8	0.1%	2.6%
Total Louisiana	109.3	152.6	261.9	34.9%	9.1%
Other States & Federal Offshore	14.3	7.3	21.6	3.0%	57.8%
Total Domestic	309.0	285.0	594.0	79.3%	40.4%
New Zealand					
Rimu/Kauri Area	73.3	15.2	88.5	11.8%	39.3%
TAWN Area	66.9	–	66.9	8.9%	77.9%
Total New Zealand	140.2	15.2	155.4	20.7%	55.9%
Total Company	449.2	300.2	749.4	100.0%	43.6%

[a]See definitions of proved reserves, proved developed reserves, and proved undeveloped reserves on page 63.

Another routine enhancement activity consists of installing small-diameter coiled tubing (velocity strings) in the wells to accelerate the upward flow of the gas and gas liquids. Five coiled tubing installations were performed in 2002, and five more are scheduled in 2003. Alternative lifting methods are also being tested.

With a special emphasis on cost savings in 2002, the effectiveness of chemicals used to inhibit corrosion in the well bores was closely monitored. As a result, annual chemical costs in the field were reduced from $1,000,000 to $500,000, and further reductions are anticipated in 2003.

During 2002, the AWP Olmos Field accounted for 21.8% (10.9 Bcfe) of the Company's total production. During 2003, Swift will resume drilling in the AWP Olmos Area on 8,833 acres near the center of its acreage under an Entity for Density approval from the Texas Railroad Commission. A total of 220 wells are now allowed within the acreage and regulatory restrictions on the locations of newly drilled wells have been removed. Also, abandoned wells may be replaced with new wells at other locations within the acreage. A total of 10 new wells are planned for 2003, with each accessing estimated unrisked reserves of 0.7 Bcfe.

MASTERS CREEK AND BROOKELAND AREAS. Swift's Masters Creek Area in Rapides Parish and Vernon Parish, Louisiana, and its Brookeland Area in Newton County and Jasper County, Texas, both produce from the Austin Chalk formation, which has natural vertical fractures that frequently contain oil and gas deposits. Wells that tap these deposits have high initial rates of production, but then settle down at lower rates. As was expected with no additional wells drilled in these areas in 2002, their combined production decreased significantly from the previous year's levels. Together, they provided 27.8% (13.8 Bcfe) of the Company's total 2002 production and held 15.6% of its year-end reserves.

Distribution of Wells in Which Swift Owned Interests As of December 31, 2002

	Wells Operated by Swift[a]	Wells Operated by Others[a]	Total Wells	Percent of Swift's Year-end Proved Reserves	Percent of Swift's 2002 Production
Texas					
AWP Area	495	–	495	30.4%	21.8%
Brookeland Area	66	32	98	6.1%	8.2%
Other Texas	50	32	82	4.9%	7.2%
Total Texas	611	64	675	41.4%	37.2%
Louisiana					
Lake Washington Area	82	8	90	25.4%	8.9%
Masters Creek Area	87	18	105	9.5%	19.6%
Other Louisiana	2	4	6	0.1%	1.1%
Total Louisiana	171	30	201	34.9%	29.6%
Other States & Federal Offshore	11	18	29	3.0%	2.0%
Total Domestic	793	112	905	79.3%	68.8%
New Zealand					
Rimu/Kauri Area	8	–	8	11.8%	3.1%
TAWN Area	19	–	19	8.9%	28.1%
Total New Zealand	27	–	27	20.7%	31.2%
Total Company	820	112	932	100.0%	100.0%
Percent of Reserves	95%	5%			
Percent of Production	95%	5%			

[a]Swift is the operator of 790 producing wells and 30 service wells. The Company has interests in 897 producing wells and 35 service wells.

While the fields in the Brookeland Area are depletion driven with little or no water production, the Masters Creek fields are water driven and require an elaborate water disposal system that includes 14 salt water disposal wells. Over the years, much attention has been given to the buildup of scale along the interior walls of the well bore tubulars, and a procedure was initiated in 2001 in which chemicals are pumped into the hole and flushed out into the formation with water to inhibit scale formation. This procedure has been highly successful—to the extent that the frequency of the chemical injections has been greatly reduced. As a result, an annual savings of about $800,000 in the costs of the Masters Creek chemicals, including those used to inhibit well pipe corrosion, has been realized.

Drilling will be resumed in both areas in 2003 with one development well planned for each area. Plans are also under way for significant future enhancements of both areas, with emphasis on in-fill drilling in the Masters Creek Area where some defined sweet spots hold estimated unrisked reserves exceeding 1.4 MMBOE per well.

Swift seeks core areas of opportunity where it can effectively apply its competitive strengths: production operations, development drilling, and innovative applications of technology. Internationally, Swift is focusing these strengths on its TAWN and Rimu/Kauri core areas in New Zealand.

New Zealand Core Areas:
Balancing domestic and international opportunities

As oil and natural gas resources in the United States mature, a key component of Swift Energy's competitive strategy is balancing opportunities at home and abroad.

In 2002, Swift recorded a major milestone in its international activities with its first commercial oil and gas production in New Zealand. The Company's New Zealand properties produced 15.5 Bcfe of oil, natural gas, and natural gas liquids in 2002, which was 31% of the Company's total production for the year. With these levels of production and cash flow, Swift's New Zealand venture has become a self-sufficient operating entity.

Swift's New Zealand production comes from the Company's two core operating areas in the Taranaki Basin of the country's north island—the TAWN Area and the Rimu/Kauri Area. The Company's proved reserves in these areas increased 53% in 2002 to 155 Bcfe, replacing 444% of their 2002 production even after including the full effect of a net downward reserves revision of approximately 21 Bcfe. At year-end 2002, New Zealand reserves constituted 21% of the Company's total reserves and consisted of 56% natural gas, 34% crude oil, and 10% natural gas liquids.

TAWN CORE AREA. With the acquisition of the TAWN Area in early 2002, Swift Energy added a second core area of operation in New Zealand and immediately became a significant producer in the country's oil and natural gas industry. For the 12 months ending June 2002, the TAWN Area accounted for approximately 4% of New Zealand's oil production and 5% of its natural gas production as reported by the New Zealand Ministry of Economic Development.

TAWN reserves, which are approximately 80% natural gas, were 66.9 Bcfe at year-end 2002, representing 8.9% of Swift's total oil and gas reserves.

Strategically located approximately 17 miles north of Swift's Rimu/Kauri Area, the TAWN Area includes four producing fields with 19 wells (including two service wells), hydrocarbon-processing facilities with excess capacity, and pipelines connecting the fields and facilities to export terminals and interior markets. The four fields include 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 field names.

In September 2002, Swift increased its ownership from 96.76% to 100% in all the TAWN petroleum mining licenses with the acquisition of interests held by a subsidiary of Bligh Oil & Minerals N. L. The transaction also included Bligh's interests in two processing plants, the Waihapa Production Station and the Tariki Ahuroa Gas Plant, as well as associated pipelines in which Swift already had a majority interest.

The TAWN processing facilities and oil and gas pipelines, together with other infrastructure in the area, all of which have current excess capacity, provide synergies with Swift's nearby Rimu/Kauri Area.

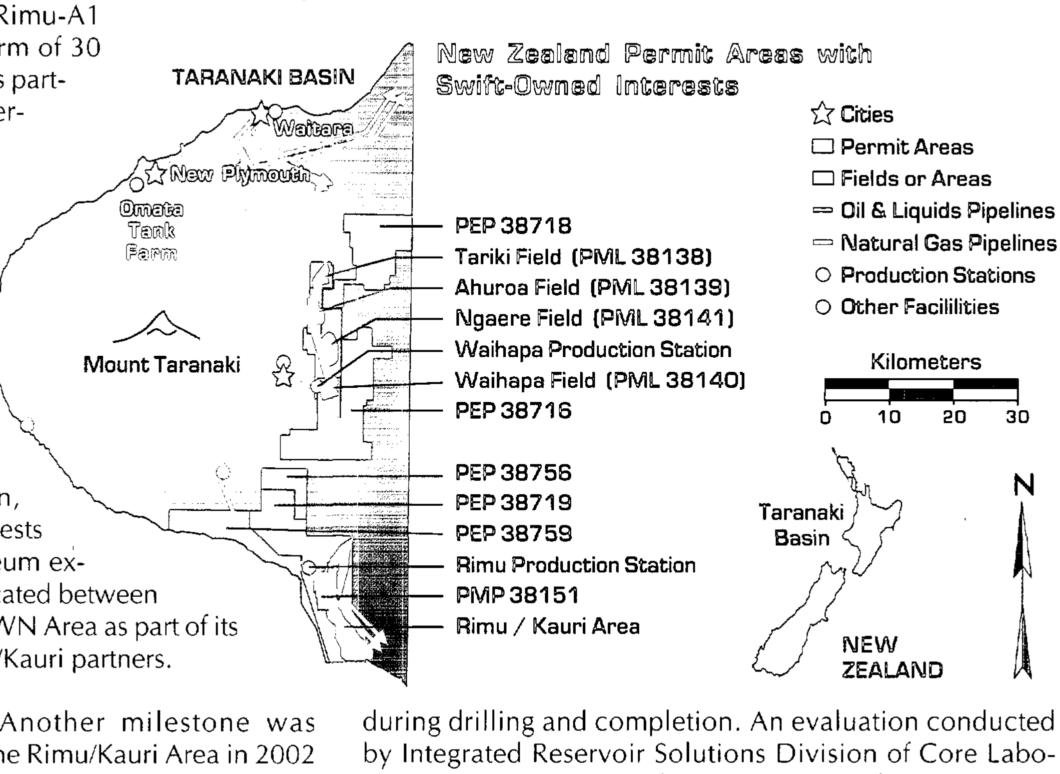
The current capacity of the processing facilities is up to 15,000 barrels of oil and condensate per day and approximately 40 million cubic feet (MMcf) of natural gas per day. Natural gas processing can be increased significantly with additional compression as needed.

A 32-mile (8-inch diameter) oil export line runs from the Waihapa Production Station to the Omata Tank Farm at New Plymouth, where oil export facilities allow for sales into international markets. A 32-mile (8-inch diameter) natural gas pipeline runs from the processing plants to the Taranaki Combined Cycle Electric Generation Facility near Stratford and on to the New Plymouth Power Station.

RIMU/KAURI CORE AREA. During 2002, Swift increased its interests in the exploration permit (PEP 38719) covering the 50,000 net-acre Rimu/Kauri Area to 100% from 90% following two separate acquisitions. In March, the Company purchased the 5% interest in the permit held by a subsidiary of Antrim Energy Inc. of Canada, and in September it purchased the remaining 5% of the permit held by a subsidiary of Bligh Oil & Minerals N.L.

Early in 2002, the New Zealand government awarded Swift a petroleum mining permit (PMP 38151) covering 5,524 acres within the Rimu/Kauri exploration permit to fully develop the area around the Rimu-A1 discovery well for a primary term of 30 years. With its purchases from its partners, Swift now has a 100% interest in this permit.

Swift also expanded its interests in areas lying adjacent to the Rimu/Kauri Area in 2002 when the New Zealand government awarded Swift two additional exploration permits (PEP 38756 and 38759) to the north and east of the Rimu/Kauri permit (PEP 38719). In addition, the Company increased its interests from 7.5% to 15% in a petroleum exploration permit (PEP 38716) located between the Rimu/Kauri Area and the TAWN Area as part of its acquisition from one of its Rimu/Kauri partners.



Rimu Production Station. Another milestone was reached in the development of the Rimu/Kauri Area in 2002 with Swift's commissioning of its Rimu Production Station. During the construction phase, New Zealand-U.S. exchange rates were at their lowest levels in over 15 years, reducing the cost of the facility for Swift.

Swift began commercial production from the facility in May 2002, less than two and a half years after the Company's initial Rimu discovery. This set a record in New Zealand for this type of facility as companies have typically needed four to eleven years to initiate production following a discovery of this type.

The station is designed to handle 3,500 barrels of oil and 10 MMcf of natural gas per day (about 31 MMcfe per day) during its first phase of operation. With minimal additional capital, the plant's capacity can be more than doubled to 8,250 barrels of oil and 20 MMcf of gas per day (approximately 70 MMcfe per day) with options for even further expansion.

Operating Activities. Swift drilled five wells in the Rimu/Kauri Area during 2002—three development wells and two exploratory wells—bringing the total number of wells drilled in the area to 13 since operations began in 1999.

However, production results for 2002 were disappointing because of formation damage found to have occurred during drilling and completion. An evaluation conducted by Integrated Reservoir Solutions Division of Core Laboratories, an international company specializing in reservoir analysis, found that the water-based fluids used during drilling and completion had caused formation damage in the Tariki sandstone surrounding the well bores. The damage, which reduced permeability, included predominantly water blockage, as well as fines migration and clay swelling.

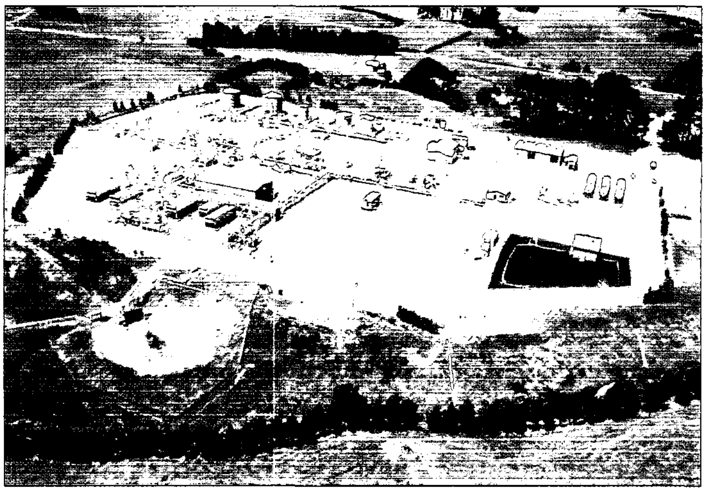
The study, which was completed in early 2003, recommended that Swift cease using water-based fluids and change the pressure levels used during perforation. The study also specified remediation activities for existing well bores, such as CO_2 injections.

Wells believed to have been affected by formation damage include all three development wells drilled in 2002: the Rimu-A2A, which was a sidetrack of the Rimu-A2 and was drilled to a depth of 13,225 feet to the Upper Tariki sand; the Rimu-B3A, which was an unsuccessful sidetrack to the Rimu-B3 and was drilled to a depth of 15,853 feet to the Upper and Lower Rimu limestones; and the Kauri-A3, which was drilled to a depth of 4,921 feet to further evaluate and delineate the shallow Manutahi sands.

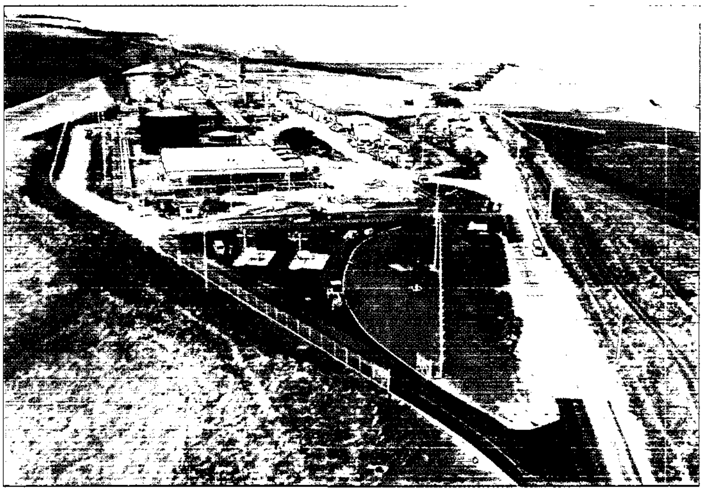
Swift's first deep exploratory well in the area, the Kauri-A1, which was drilled early in 2002 to a depth of 14,764 feet to the Kauri and Upper Tariki sands, also appears to have been affected. Before the second exploratory well, the Kauri-A4, was spudded in June, the Company's own preliminary analysis had indicated that oil-based drilling fluids might improve the well's productibility. As a result, the Company drilled the Kauri-A4 well with an oil-based drilling fluid. The well reached a total measured depth of 15,252 feet (true vertical depth of 13,277 feet) and intersected several of its primary targeted intervals, including the Kauri sands, the Lower Tariki sand, and the Cretaceous sands. It also intersected a targeted seismic anomaly that had been identified just above the Kauri sands and intersected in the Kauri-A1 well. While of excellent sand quality, the lower sands in the Kauri-A4 well were deemed noncommercial, and the well was tested in the Kauri sands found at a depth of 7,879 feet, where it flowed naturally at rates that averaged approximately 2.1 MMcfe per day. The well will be hydraulically fractured in the Kauri sands using the recommended procedures during the first half of 2003.

Other activities scheduled for the first half of the year include drilling a well in the shallow Manutahi sand (the Kauri-F1) using the new procedures and conducting remediation efforts with CO_2 injection in the Tariki sand in the Rimu-A2A well. In addition, artificial lift operations will begin on the Kauri-A2 and A3 following the installation of pumping units. Based upon the outcome of these efforts, additional drilling in the Rimu/Kauri Area may be undertaken during the second half of the year.

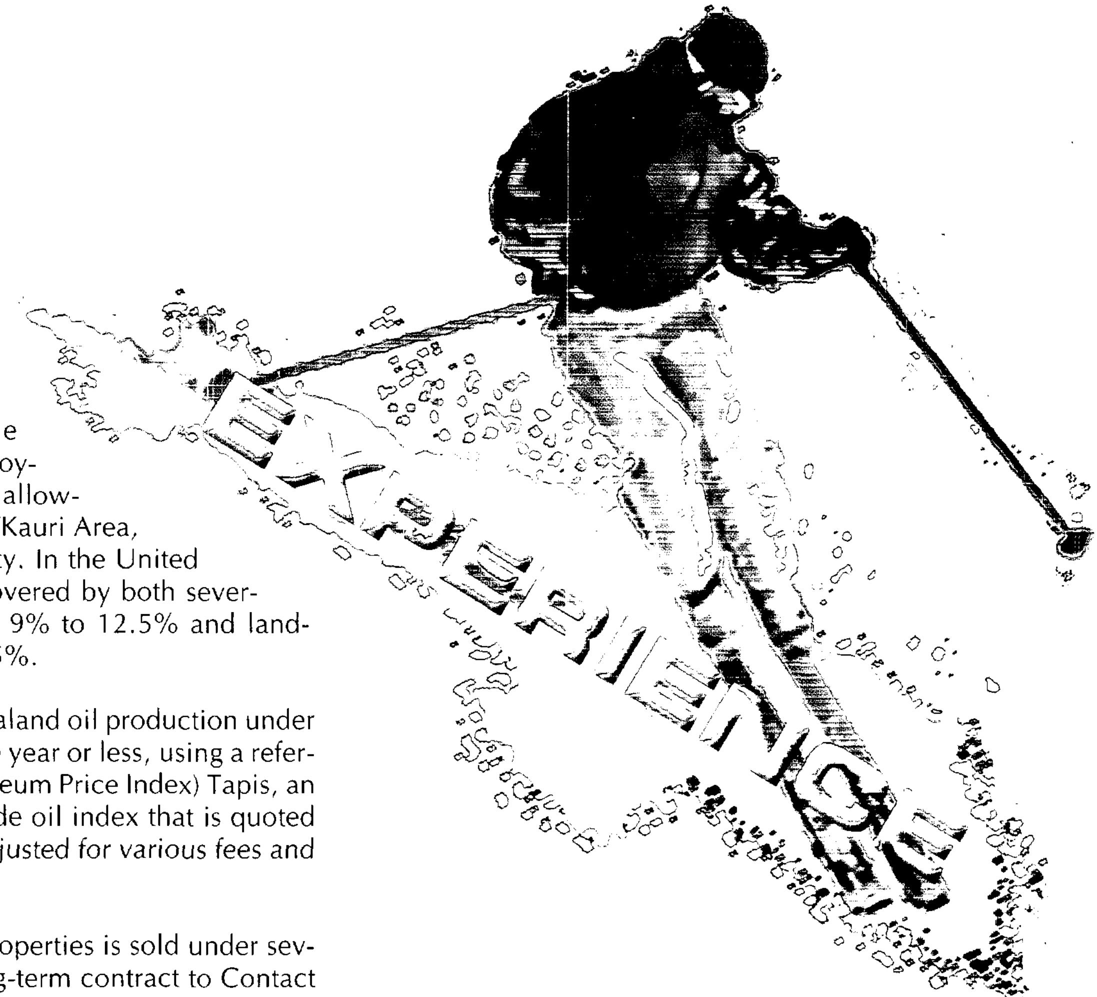
MARKETING. Swift's production from the TAWN Area and Rimu/Kauri Area is marketed under several arrangements. During 2002, Swift's average price received in New Zealand was $24.31 per barrel for oil, $11.06 per barrel for natural gas liquids, and $1.32 per Mcf for natural gas. Over the long term, as natural gas production declines at New Zealand's largest natural gas field, the Maui Field, price appreciation for natural gas in New Zealand is expected to occur. Production from the Maui Field could reach depletion as early as 2007, according to various industry and government analyses.



Swift's Waihapa Production Station and its Tariki Ahuroa Gas Plant process oil and gas from the Company's TAWN Area, which supplied approximately 4% of New Zealand's national oil production and 5% of its natural gas production for the 12-month period ending June 2002.



The Rimu Production Station began commercial production in May 2002. Swift built the facility in less than two and one-half years, compared to the four to eleven years previously taken by others to initiate production elsewhere in New Zealand.



Favorably impacting revenues from oil and gas sales are the rates of New Zealand's government royalties as compared to the U.S. equivalent. For the TAWN Area, Swift pays a 10% royalty on net sales revenues after allowable deductions. For the Rimu/Kauri Area, it pays a 5% ad valorem royalty. In the United States, Swift's production is covered by both severance and ad valorem taxes of 9% to 12.5% and landowner royalties of 12.5% to 25%.

Swift generally sells its New Zealand oil production under short-term contracts lasting one year or less, using a reference price of APPI (Asian Petroleum Price Index) Tapis, an internationally recognized crude oil index that is quoted at least weekly. The price is adjusted for various fees and premiums.

Natural gas from the TAWN properties is sold under several contracts, including a long-term contract to Contact Energy Limited. At year-end 2002, 69% of TAWN's proved natural gas reserves were associated with this long-term natural gas contract. Swift has negotiated for any excess deliverability to be sold at current market rates.

Swift's natural gas production from the Rimu/Kauri Area is sold under an agreement with Genesis Power Limited, a New Zealand state-owned enterprise, to provide 40 petajoules (approximately 38 Bcf) of natural gas over a 10-year period that began in 2002.

LONG-TERM OUTLOOK. Swift made significant progress in its New Zealand operations in 2002 with the start of commercial production, the acquisition of the TAWN Area, the completion of the Rimu Production Station, and the increased understanding of the complexity of the Tariki reservoir.

With its 100% ownership of interests in the TAWN Area and the Rimu/Kauri Area and their close physical locations, the Company's long-term view is that the fields and infrastructure in these two core areas will eventually be integrally connected. This consolidated position will be one more step in Swift developing a significant presence in New Zealand and increasing its synergies in the Taranaki Basin. In addition, both the TAWN Area and the Rimu/Kauri Area offer on-going exploration potential as discussed on pages 16-17 of this report.

Assembling teams of experienced professionals is key to Swift Energy's success. With a high level of technical skill in petroleum engineering, geology, geophysics, and land, Swift's staff has the expertise needed to succeed in exploration and acquisition activities.

Future Growth Opportunities:
Balancing exploration and acquisitions

In 2003 and beyond, Swift's pursuit of long-term growth opportunities will continue to focus on the Gulf Coast in the United States and the Taranaki Basin in New Zealand. Both regions provide unexploited potential close to growing markets facing tighter future supplies, and they are both prime areas where Swift can expand profitability.

DOMESTIC EXPLORATION ACTIVITIES. In its exploratory program in the United States, Swift drilled or participated in seven exploratory wells with three successes in 2002. In 2003, the Company has plans to drill four to eight exploratory wells in the Gulf Coast region, depending on oil and gas pricing trends and Company performance. Swift has identified a total of 23 potential prospects in this region, including those targeted for 2003.

In Texas, Swift's 2003 prospects include three in the Frio sands (the Venice prospect in Kenedy County and the Pisa and West Pisa prospects that lie along the border of Kenedy and Willacy counties), one in the Wilcox sands (the Pearl prospect in Lavaca County), and two in the Woodbine sands (the Jaguar and Bobcat prospects, both in Polk County).

In Louisiana, Swift has two Miocene prospects planned for 2003 located in the Lake Washington Area in Plaquemines Parish.

The Frio Trend (Garcia Ranch). Swift has a total of nine prospects in the deep sands of the Frio formation (10,000 to 16,500 feet) in Kenedy County and Willacy County in the southern tip of Texas, a region that the Company hopes to develop into a new core operating area. Most of the prospects are in a region known as Garcia Ranch, which straddles the border of the two counties. Swift had two discoveries in this area in 2001.

Swift developed its prospects in this area by analyzing three-dimensional seismic data and geological projections based on well-bore data from producing wells.

The Wilcox Sands. Swift has identified eight potential prospects in the deep Wilcox sands located in the Texas counties of Lavaca, DeWitt, Victoria, and Goliad. In 2001, the Company had two discoveries in this area, both in Goliad County.

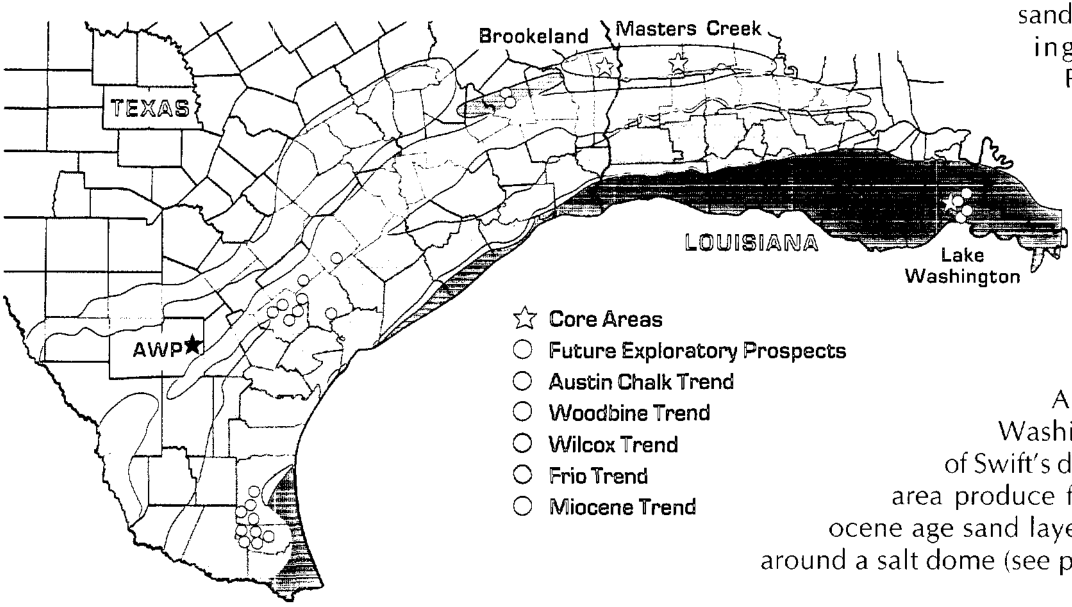
Swift's prospects in the Wilcox sands are based on the Company's analysis of two- and three-dimensional seismic data.

The Woodbine Formation. Swift has two prospects in the Woodbine trend in Polk County, Texas, where the Company has analyzed the region around the Double A Wells Field that has successfully produced from the Woodbine sands since 1985.

The Miocene Sands. Swift has identified four prospects in the deep Miocene sands in the Company's Lake Washington Area located in Plaquemines Parish in Louisiana, with two scheduled for drilling in 2003. One prospect lies in the deep sands on the northeast flank of the salt dome while the other three are located in the deep sands on the south flank of the dome.

Acquired in 2001, the Lake Washington Area was the site of two of Swift's discoveries in 2002. Wells in this area produce from an east-west trend of Miocene age sand layers that lie one above the other around a salt dome (see page 8).

Swift's Core Areas and Future Exploration Prospects



Industry and economic conditions caused Swift to defer further drilling in the Garcia Ranch region in 2002 except for participating in one well, the Burns #1 drilled in Kenedy County on the Milan prospect that Swift developed. The well, in which the Company holds a 33% working interest, averaged 3.6 MMcfe per day during a 10-day test period.

NEW ZEALAND EXPLORATION ACTIVITIES. Swift has drilled two deep exploratory wells in its Rimu/Kauri Area in the Taranaki Basin, the Kauri-A1 and the Kauri-A4, both drilled in 2002. During the first half of 2003, the Kauri-A4 will be hydraulically fractured using recommendations of the reservoir evaluation (see pages 13-14), and depending upon its success, further activity will be undertaken.

Swift currently has four exploration prospects in New Zealand, three of which are located in or near Swift's core areas of operations (see map on page 13). The Matai prospect and the Tawa prospect are covered by the same exploratory permit (PEP 38719) as the Rimu/Kauri Area, and the Waihapa prospect is located in Swift's TAWN Area (PML 38140). The Tuihu prospect (PEP 38718), in which Swift increased its interests from 20% to 50% in early 2003, is north of the TAWN Area. In addition, in 2002 the New Zealand government awarded Swift 100% working interests in two more exploration permits covering acreage adjacent to the Rimu/Kauri permit (PEP 38759 and PEP 38756).

During 2003, Swift plans to drill the Tawa prospect and/or the Matai prospect, which are overlapping prospects northwest of the Rimu/Kauri Area. The Tawa prospect is a stratigraphic trap where Swift will target the Kauri sands, the Tariki sandstone, and the Kapuni sands. The shallower Matai prospect, located on the southeast flank of the Tawa prospect, was originally identified on the basis of the analysis of two-dimensional seismic data that Swift acquired in 2000 and was further analyzed on the basis of additional two-dimensional seismic data obtained over 17 kilometers in 2002. It is a structural trap with a four-way closure and will target the Urenui and the Moki sandstones.

Swift also has scheduled a re-entry of the Tuihi #1 in 2003 to sidetrack or deepen a well drilled on the Tuihu prospect in 2001. The targeted sands will be the Tariki and Kapuni sands.

ACQUISITIONS OF PRODUCING PROPERTIES. When pursuing acquisition opportunities, Swift focuses on properties where it can obtain significant working interests and serve as the operator. The Company generally seeks properties within concentrated geographic areas. This provides economies of scale and allows Swift's staff to better use its technical expertise to enhance production through development drilling and operational improvements.

During 2002, Swift's major acquisition was of the TAWN Area in the Taranaki Basin of New Zealand, which is located only 17 miles from Swift's Rimu/Kauri Area. Subsequently in 2002, Swift increased its interests in the TAWN Area from 96.76% to 100% and its interest in the Rimu/Kauri Area from 90% to 100% (see pages 12-13).

Flexibility is an important element of Swift's financial strategy. In 2002, the Company improved its financial flexibility with a public offering of senior subordinated notes accompanied by an offering of common stock.

Financial Flexibility:

Balancing debt and equity

Any industry as dynamic as oil and gas will create new growth opportunities. But in a rapidly changing environment, successful companies must be capable of responding quickly when the market changes direction. Swift maintains the financial flexibility to respond to new opportunities as they arise by maintaining an appropriate balance between debt and equity.

Achieving a healthy mix of debt and equity is an ongoing process. During 2002, the Company significantly improved its financial flexibility through a public offering of senior subordinated notes accompanied by a public stock offering.

In April 2002, the Company sold $200 million of senior subordinated notes with an interest rate of 9.375%. The proceeds from this offering were used to pay down outstanding indebtedness on the Company's credit facility. This long-term debt more effectively matches the recently acquired long-lived assets of the Lake Washington Field, the Rimu properties, and the TAWN properties that were previously financed through a short-term credit facility with Swift's bank group.

In the accompanying public offering of 1,725,000 shares of common stock, Swift also used the net proceeds of approximately $30.5 million to pay down outstanding indebtedness on the Company's credit facility. At year-end 2002, following these successful debt and equity offerings, working capital had improved by $19 million.

Other financial highlights of 2002 included Swift's receipt of $7.5 million for its interest in the Samburg project located in Western Siberia, Russia, as a result of the sale by a third party of its ownership in a Russian joint stock company that owned and operated this field. The Company also completed the liquidation of its public partnerships in 2002.

PURSUING OPPORTUNITIES. Swift's capital budget for 2003 is projected to range from $115 million to $130 million (exclusive of acquisitions), depending in large part on the performance of oil and natural gas prices and Company successes during the year. The Company plans to begin the year at the low end of the budget range and then increase expenditures incrementally as warranted.

Approximately 85% of the budget is targeted for domestic activities, primarily in the Lake Washington Area, with about 15% planned for New Zealand activities. The budget is net of approximately $5 million to $15 million of noncore property dispositions that are planned for later in the year.

Domestically, the 2003 budget designates $90 million to $105 million for development drilling and $3 million to $7 million for exploratory drilling. The Company has budgeted $15 million to $19 million for its New Zealand activities. Prospect costs, including seismic activities, are estimated to be within a range of $12 million to $14 million.

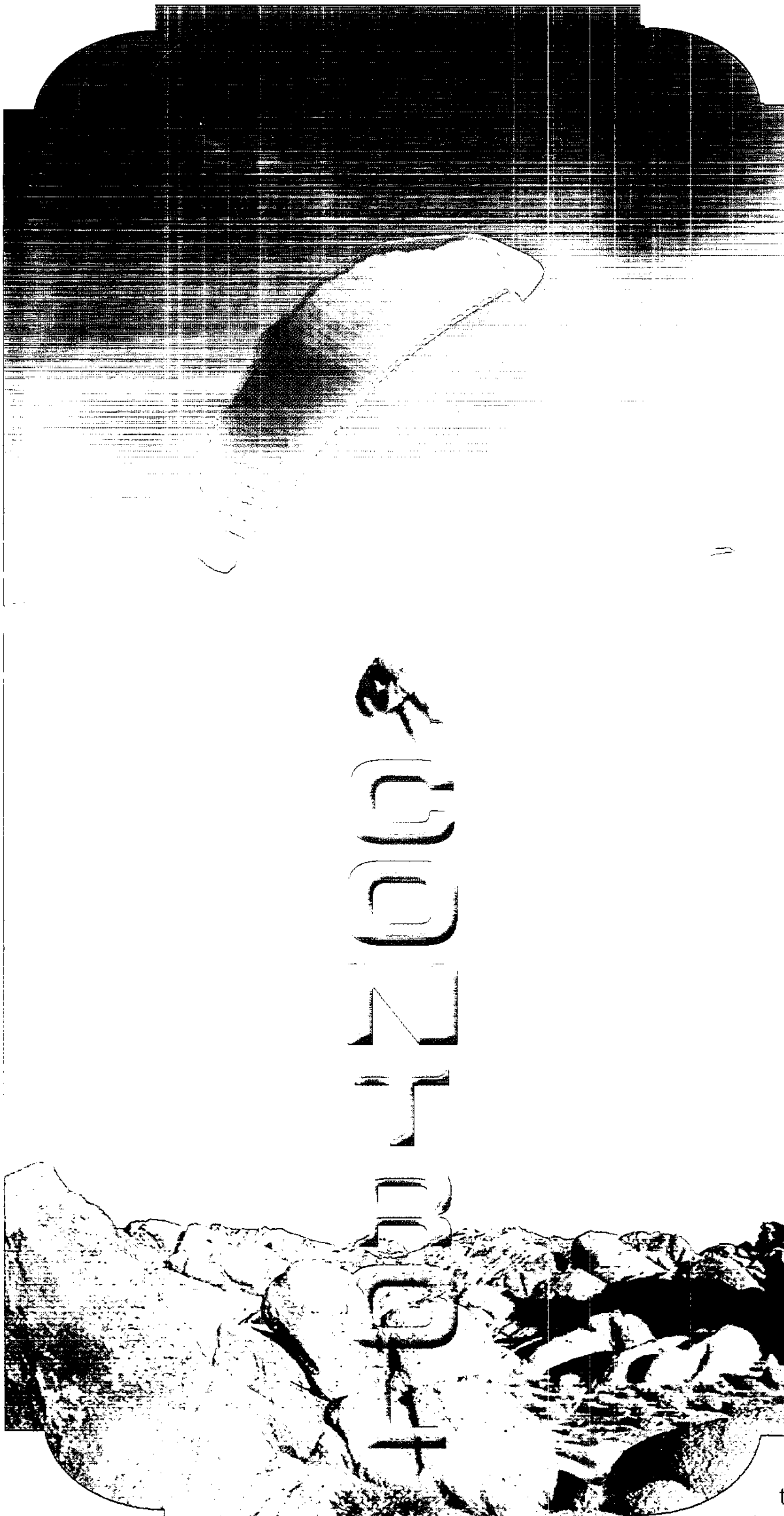
Should strategic acquisition opportunities arise in 2003, Swift would balance the appropriate mix of debt and/or equity for the transaction.

IMPROVING CREDIT PROFILE. Moving forward in 2003, Swift's revolving line of credit through a nine-member bank group is available to the Company as a cost-effective way of increasing access to capital. The borrowing base under this revolving credit facility was reaffirmed at $195 million in late 2002, with no outstanding balance at year-end. Earlier in 2002, Swift reduced its borrowing base from $275 million to the current $195 million following the closing of the successful note offering.

While the credit agreement extends through 2005 and is treated as long-term debt on the balance sheet, the terms of the agreement specify short-term interest rates. The specified interest rate is Swift's choice of the prime rate or the adjusted London Interbank Offered Rate (LIBOR). As of February 28, 2003, the prime rate was 4.25%, and the 30-day LIBOR rate plus its applicable margin was 2.59%.

MANAGING RISK. Swift also enhances financial flexibility by actively managing the risks associated with volatile oil and natural gas pricing. Swift has in place a three-pronged strategy for price-risk management that focuses on alternatives to protect cash flow and capital budget plans while maintaining upside potential.

First, a portion of oil and natural gas production is safeguarded against rapid price declines through the use of price floors and participating collars. Swift's Price Risk Management Committee monitors volatility and considers, among other factors, when oil or natural gas prices surpass one standard deviation of five-year pricing averages. Over the past 10 years, 38% of natural gas production has been protected at an average cost of $0.04 per Mcf and 37% of oil production has been protected at an average cost of $0.19 per barrel. In 2003, an estimated 25% to 60% of production may be safeguarded with price floors and participating collars, depending on production volumes and pricing trends.



A culture of openness and communication, along with many years of experience in working together, has allowed Swift's management team to develop a high degree of internal coordination and control, enabling the Company to respond efficiently to changes in the external environment.

Second, Swift's long-term natural gas contracts in New Zealand provide an effective hedge. Such contracts were executed with two of the three largest electric utilities in New Zealand.

Third, Swift uses a portfolio approach to oil and natural gas sales. By making sales to a wide variety of purchasers, diversity is maintained in oil and gas marketing.

Swift's staff monitors price-risk management activities daily, seeking to conservatively balance risks and rewards with regard to current and emerging economic and industry trends.

LOOKING AHEAD. Financial flexibility is crucial to the Company's overall competitive strategy. With the issuance of debt and equity in 2002, the adoption of a more balanced approach to risks and rewards that reflects the new economic and industry trends, and a more flexible credit profile, Swift is positioned to take advantage of the opportunities offered in the years ahead.

Management Controls:
Balancing authority, teamwork, and innovation

Swift Energy's founder and chairman of the board, A. Earl Swift, has long said that one of the most vital responsibilities of a company's leadership is to balance the three main aspects of decision making—individual initiative, team consensus, and authoritative control and oversight.

This balance provides the creativity and flexibility needed to respond quickly to changes in the competitive environment, while also guaranteeing a measure of control and transparency within a system of checks and balances. A fundamental aspect of this philosophy is a dedication to the free flow of information between a company and its investors and also between internal departments.

The effectiveness of this approach was particularly evident at Swift Energy in 2002 when major strategic changes had to be quickly put into place in response to the economic and industry upheaval that occurred during 2001. Swift's responses were overseen by a management team comprised of 14 officers, 13 of whom have been working together for a decade or longer. They joined with small, interdisciplinary teams of employees from a range of departments to rebalance all aspects of Swift's competitive strategy.

The continuity of leadership that Swift enjoys has resulted at least in part from the Company's policy of promoting employees from within who have been instrumental to past successes. One long-serving member of this management team was promoted in early 2003. James P. Mitchell was named senior vice president–commercial transactions and land. Mr. Mitchell, who has been with the Company since 1987 previously served as vice president–land and property transactions.

In addition to internal principles, outside measures of accountability are also highly valued at Swift. For many years, long before the recent emphasis on corporate accountability, a majority of Swift's Board of Directors have been outside "independent" directors. Most of the board's committees are comprised entirely of outside directors, including the Audit Committee, the Compensation Committee, the Corporate Governance Committee, and the Special Transactions Committee.

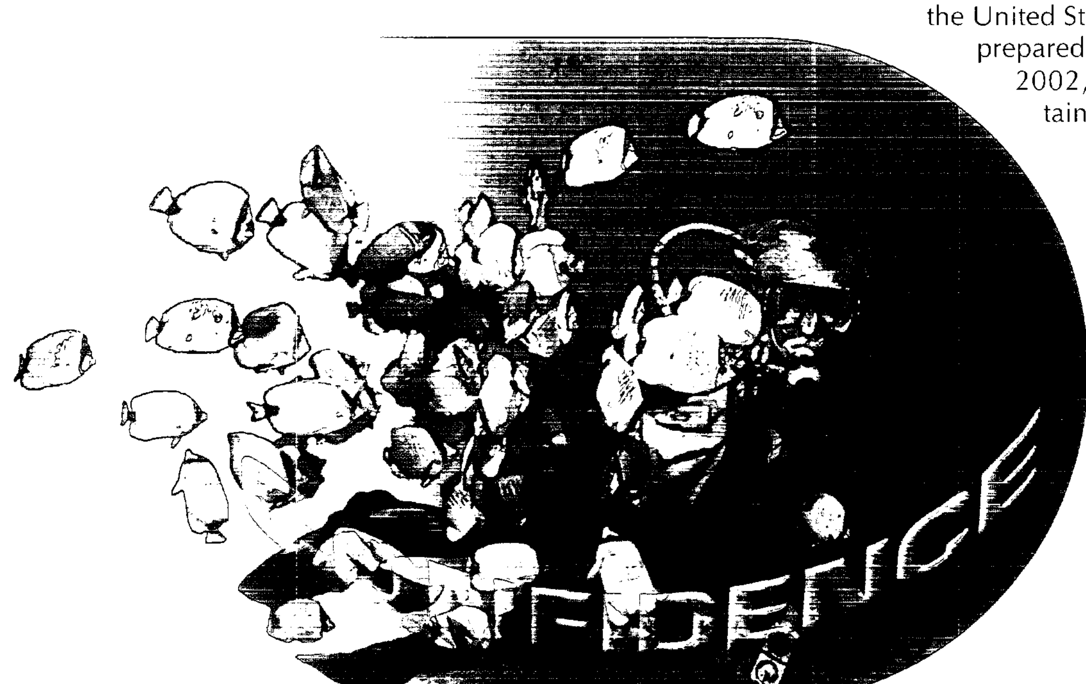
The Company's newest outside director is R.E. "Ray" Galvin, who was appointed to the board on August 5, 2002. Mr. Galvin retired in February 1997 as president of Chevron U.S.A. Production Co. and as a director and vice president of Chevron Corporation.

The independent auditors and consultants on whom Swift relies include Ernst & Young, a big-four accounting firm; Jenkens & Gilchrist, a 50-year-old national law firm specializing in public company and energy representation; and H.J. Gruy & Associates, international oil and gas engineering and geological consultants with more than 50 years of experience.

The same principles of balance and openness that are trademarks of Swift Energy in the United States are being built into the Company's growing organization in New Zealand, Swift Energy New Zealand Limited (SENZ). SENZ is a New Zealand company incorporated on June 6, 1997, that is a wholly owned subsidiary of Swift Energy International, Inc., a Texas corporation, which in turn is a wholly owned subsidiary of Swift Energy Company.

The seasoned management put into place at SENZ is a blend of employees who formerly worked for Swift at its Houston offices and other professionals from both New Zealand and the United States.

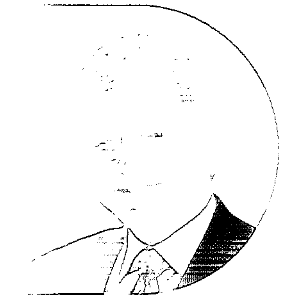
With these cohesive management teams in place in the United States and New Zealand, Swift is prepared to build upon its successes in 2002, focusing on achieving sustained growth in shareholder value.



With a lower decline rate, improved financial flexibility, and a considerable inventory of undeveloped and potential reserves, Swift is now in a better position to pursue long-term growth opportunities. The Company's management is confident in its strategies and optimistic about the future.

SWIFT ENERGY COMPANY OFFICERS

Terry E. Swift
President
Chief Executive Officer



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

Bruce H. Vincent
Executive Vice President-Corporate Development, Secretary

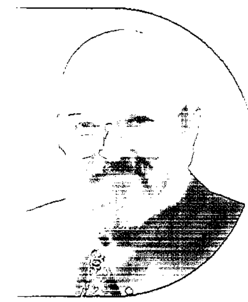
Alton D. Heckaman, Jr.
Senior Vice President-Finance, Chief Financial Officer

James M. Kitterman
Senior Vice President-Operations

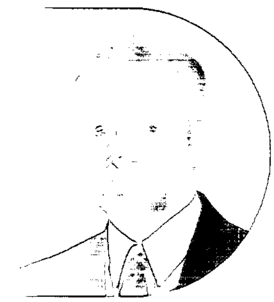
James P. Mitchell
Senior Vice President-Commercial Transactions and Land

Victor R. Moran
Senior Vice President-Energy Marketing & Business Development

Gerald B. Long
Vice President-Production Operations



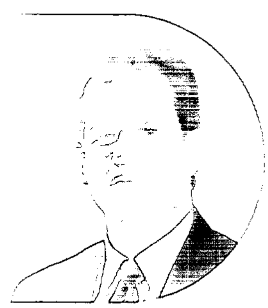
Khushroo N. J. Patel
Vice President-Geophysics



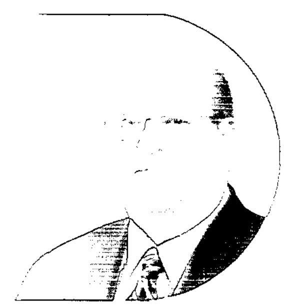
Thomas E. Schmidt
Vice President-Exploration & Development

Tara L. Seaman
Vice President-Acquisitions, Dispositions & Reserves

Adrian D. Shelley
Treasurer



David W. Wesson
Controller



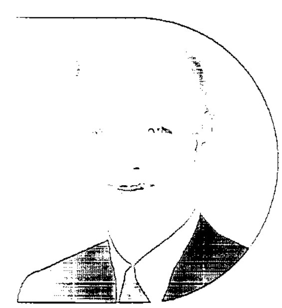
D. Wynn Ibach
General Counsel

SWIFT ENERGY NEW ZEALAND OFFICERS

Donald L. Morgan
Chairman
Chief Executive Officer

R. Alan Cunningham
President
Chief Operating Officer

Steven B. Yakle
Vice President-Finance
Chief Financial Officer, Secretary



Christopher J. T. Bush
Vice President-Facilities

BOARD OF DIRECTORS


A. Earl Swift
Chairman of the Board,
Age 69


Virgil N. Swift
Vice Chairman of the Board,
Age 74


Terry E. Swift
President &
Chief Executive Officer,
Age 47


G. Robert Evans
Retired Chairman & CEO,
Material Sciences
Corporation, Age 71


Raymond E. Galvin
Retired President,
Chevron U.S.A.
Production
Company, Age 71


Henry C. Montgomery
Chairman & Founder,
Montgomery Financial
Services Corporation,
Age 67


Clyde W. Smith, Jr.
President,
Ascentron, Inc.,
Age 54


Harold J. Withrow
Consultant,
Age 75


Raymond O. Loen
Director Emeritus,
Age 78

Board of Directors Committees:

Audit Committee—Henry C. Montgomery, Chairman,
G. Robert Evans, Clyde W. Smith, Jr.
Compensation Committee—Clyde W. Smith, Jr., Chairman,
Raymond E. Galvin, Henry C. Montgomery, Harold J. Withrow.
Executive Committee—A. Earl Swift, Chairman,
Terry E. Swift, Virgil N. Swift, Harold J. Withrow,
Corporate Governance Committee—G. Robert Evans, Chairman,
Raymond E. Galvin, Clyde W. Smith, Jr., Harold J. Withrow.
Special Transactions Committee—Harold J. Withrow, Chairman,
G. Robert Evans, Raymond E. Galvin, Henry C. Montgomery, Clyde W. Smith, Jr.

FINANCIAL REPORT

Selected Financial and Operating Data

	2002	2001	2000	1999
Revenues				
Oil and Gas Sales	$141,195,713	$181,184,635	$189,138,947	$108,898,696
Fees and Earned Interests[2]	$67,173	$427,583	$331,497	$229,749
Interest Income	$263,738	$49,281	$1,339,386	$833,204
Other, Net	$8,443,187	$2,145,991	$815,116	$709,358
Total Revenues	$149,969,811	$183,807,490	$191,624,946	$110,671,007
Operating Income (Loss)	$18,408,289	$(34,192,333)	$93,079,346	$29,736,151
Net Income (Loss)	$11,923,227	$(22,347,765)	$59,184,008	$19,286,574
Net Cash Provided by Operating Activities	$71,626,314	$139,884,255	$128,197,227	$73,603,426
Per Share Data				
Weighted Average Shares Outstanding[3]	26,382,906	24,732,099	21,244,684	18,050,106
Earnings (Loss) per Share—Basic[3]	$0.45	$(0.90)	$2.79	$1.07
Earnings (Loss) per Share—Diluted[3]	$0.45	$(0.90)	$2.51	$1.07
Shares Outstanding at Year-End	27,201,509	24,795,564	24,608,344	20,823,729
Book Value per Share	$13.42	$12.61	$13.50	$8.18
Market Price[3]				
High	$20.58	$37.70	$43.50	$13.31
Low	$6.80	$16.66	$9.75	$5.69
Year-End Close	$9.67	$20.20	$37.63	$11.50
Pro forma amounts assuming 1994 change in accounting principle is applied retroactively[2]				
Net Income (Loss)	—	—	—	—
Earnings (Loss) per Share—Basic[3]	—	—	—	—
Earnings (Loss) per Share—Diluted[3]	—	—	—	—
Assets				
Current Assets	$29,768,199	$36,752,980	$41,872,879	$50,605,488
Oil and Gas Properties, Net of Accumulated Depreciation, Depletion, and Amortization	$721,617,941	$628,304,060	$524,052,828	$392,986,589
Total Assets	$767,005,859	$671,684,833	$572,387,001	$454,299,414
Liabilities				
Current Liabilities	$46,884,184	$73,245,335	$64,324,771	$34,070,085
Long-Term Debt	$324,271,973	$258,197,128	$134,729,485	$239,068,423
Total Liabilities	$401,932,675	$359,032,113	$240,232,846	$283,895,297
Stockholders' Equity	$365,073,184	$312,652,720	$332,154,155	$170,404,117
Number of Employees	234	209	181	173
Producing Wells				
Swift Operated	820	854	817	769
Outside Operated	112	381	711	788
Total Producing Wells	932	1,235	1,528	1,557
Wells Drilled (Gross)	36	53	70	27
Proved Reserves				
Natural Gas (Mcf)	326,731,672	324,912,125	418,613,976	329,959,750
Oil, NGL, & Condensate (barrels)	70,438,963	53,482,636	35,133,596	20,806,263
Total Proved Reserves (Mcf equivalent)	749,365,449	645,807,939	629,415,552	454,797,327
Production (Mcf equivalent)[4]	49,752,346	44,791,202	42,356,705	42,874,303
Average Sales Price				
Natural Gas (per Mcf)	$2.30	$4.23	$4.24	$2.40
Oil (per barrel)	$20.88	$22.64	$29.35	$16.75

[1] Additional 1994 Data: Income Before Cumulative Effect of Change in Accounting Principle–$3,725,671; Cumulative Effect of Change in Accounting Principle–$(16,772,698); Per Share Amounts–Basic–Income Before Cumulative Effect of Change in Accounting Principle–$0.51, Cumulative Effect of Change in Accounting Principle–$(2.29); Per Share Amounts–Diluted–Income Before Cumulative Effect of Change in Accounting Principle–$0.51, Cumulative Effect of Change in Accounting Principle–$(2.29).

[2] As of January 1, 1994, we changed our revenue recognition policy for earned interests. Accordingly, in 1994 to 1999, "Fees and Earned Interests" does not include earned interests revenues.

[3] Amounts have been retroactively restated in all periods presented to give recognition to: (a) an equivalent change in capital structure as a result of two 10% stock dividends, one in September 1994, the other in October 1997; and (b) the adoption in 1998 of Statement of Financial Accounting Standards No. 128, "Earnings per Share."

[4] Natural gas production for 1992, 1993, 1994, 1995, 1996, 1997, 1998, 1999, and 2000 includes 1,148,862, 1,581,206, 1,358,375, 1,211,255, 1,156,361, 1,015,226, 866,232, 728,235, and 405,130 Mcf, respectively, delivered under our volumetric production payment agreement.

1998	1997	1996	1995	1994[1]	1993	1992
$80,067,837	$69,015,189	$52,770,672	$22,527,892	$19,802,188	$15,535,671	$12,420,222
$333,940	$745,856	$937,238	$590,441	$701,528	$4,071,970	$2,716,277
$107,374	$2,395,406	$433,352	$212,329	$47,980	$201,584	$113,387
$1,960,070	$2,555,729	$2,156,764	$1,761,568	$1,072,535	$604,599	$515,931
$82,469,221	$74,712,180	$56,298,026	$25,092,230	$21,624,231	$20,413,824	$15,765,817
$(73,391,581)	$33,129,606	$28,785,783	$6,894,537	$4,837,829	$6,628,608	$4,687,519
$(48,225,204)	$22,310,189	$19,025,450	$4,912,512	$(13,047,027)	$4,896,253	$4,084,760
$54,249,017	$55,255,965	$37,102,578	$14,376,463	$10,394,514	$7,238,340	$6,349,080
16,436,972	16,492,856	15,000,901	10,035,143	7,308,673	7,246,884	6,748,548
$(2.93)	$1.35	$1.27	$0.49	$(1.79)	$0.68	$0.61
$(2.93)	$1.26	$1.25	$0.49	$(1.79)	$0.64	$0.61
16,291,242	16,459,156	15,176,417	12,509,700	6,685,137	6,001,075	5,968,579
$6.71	$9.69	$9.41	$7.46	$6.30	$9.08	$8.26
$21.00	$34.20	$28.86	$11.48	$10.35	$11.57	$7.85
$6.94	$16.93	$9.89	$7.05	$7.75	$7.14	$4.65
$7.38	$21.06	$27.16	$10.91	$8.86	$7.85	$7.55
—	—	—	—	$3,725,671	$4,322,478	$3,729,851
—	—	—	—	$0.51	$0.60	$0.55
—	—	—	—	$0.51	$0.57	$0.55
$35,246,431	$29,981,786	$101,619,478	$43,380,454	$39,208,418	$65,307,120	$30,830,173
$356,711,711	$301,312,847	$200,010,375	$125,217,872	$88,415,612	$89,656,577	$64,301,509
$403,645,267	$339,115,390	$310,375,264	$175,252,707	$135,672,743	$160,892,917	$100,243,469
$31,415,054	$28,517,664	$32,915,616	$40,133,269	$52,345,859	$55,565,437	$27,876,687
$261,200,000	$122,915,000	$115,000,000	$28,750,000	$28,750,000	$28,750,000	$0
$294,282,628	$179,714,470	$167,613,654	$81,906,742	$93,545,612	$106,427,203	$50,962,183
$109,362,639	$159,400,920	$142,761,610	$93,345,965	$42,127,131	$54,465,714	$49,281,286
203	194	191	176	209	188	178
836	650	842	767	750	795	688
917	917	986	3,316	3,422	3,407	1,978
1,753	1,567	1,828	4,083	4,172	4,202	2,666
75	182	153	76	44	34	40
352,400,835	314,305,669	225,758,201	143,567,520	76,263,964	64,462,805	41,638,100
13,957,925	7,858,918	5,484,309	5,421,981	4,553,237	4,271,069	2,901,621
436,148,385	361,459,177	258,664,055	176,099,406	103,583,566	90,089,219	59,047,824
39,030,030	25,393,744	19,437,114	11,186,573	9,600,867	7,368,757	5,678,772
$2.08	$2.68	$2.57	$1.77	$1.93	$1.96	$1.90
$11.86	$17.59	$19.82	$15.66	$14.35	$15.10	$17.19

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with our Consolidated Financial Statements and Notes thereto.

General

Over the last three years, we have emphasized adding reserves through drilling activity, while adding reserves through strategic purchases of producing properties when oil and gas prices were at lower levels and other market conditions were appropriate. We used this flexible strategy of employing both drilling and acquisitions to add more reserves than we depleted through production during this period.

Proved Oil and Gas Reserves. At year-end 2002, our total proved reserves were 749.4 Bcfe with a PV-10 Value of $1.2 billion. In 2002, our proved natural gas reserves increased 1.8 Bcf, or 1%, while our proved oil reserves increased 17.0 MMBbl, or 32%, for a total equivalent increase of 103.6 Bcfe, or 16%. In 2001, our proved natural gas reserves decreased by 93.7 Bcf, or 22%, while our proved oil reserves increased by 18.3 MMBbl, or 52%, for a total equivalent increase of 16.4 Bcfe, or 3%. We added reserves in 2002 through both our drilling activity and through purchases of minerals in place. Through drilling we added 83.9 Bcfe (15.9 Bcfe of which came from New Zealand) of proved reserves in 2002, 105.8 Bcfe (17.4 Bcfe of which came from New Zealand) in 2001, and 184.7 Bcfe (122.5 Bcfe of which came from New Zealand) in 2000. Through acquisitions we added 74.2 Bcfe of proved reserves in 2002, 54.6 Bcfe in 2001, and 39.7 Bcfe in 2000. At year-end 2002, 60% of our total proved reserves were proved developed, compared with 50% at year-end 2001 and 45% at year-end 2000.

Our total proved reserves quantities at year-end 2002 increased by 16% over reserves quantities a year earlier, while the PV-10 Value of those reserves increased 93% from the PV-10 Value at year-end 2001. Gas prices increased in 2002 to $3.49 per Mcf from $2.51 per Mcf at year-end 2001, compared to $9.86 per Mcf at year-end 2000. Oil prices increased in 2002 to $29.27 per barrel from $18.45 per Bbl at year-end 2001, compared to $24.62 in 2000. Under SEC guidelines, estimates of proved reserves must be made using year-end oil and gas sales prices and are held constant 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. While our total proved reserves quantities increased by 3% during 2001, the PV-10 Value of those reserves decreased 74%, due to much lower prices at year-end 2001 than at year-end 2000. Between those two year-ends, there was a 75% decrease in natural gas prices and a 25% decrease in oil prices. This decrease in prices resulted in 47.1 Bcfe of downward reserves revisions, solely attributed to the decrease in prices at year-end 2001. The year-end 2001 gas price of $2.51 was significantly lower than the average gas price of $4.23 we received during 2001. The year-end 2001 oil price of $18.45 per barrel was also lower than the average oil price of $22.64 we received in 2001.

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter are as follows:

	2003	2004	2005	2006	2007	Thereafter[3]
Non-cancelable operating lease commitments	$2,190,363	$2,191,495	$ 523,755	$ 190,676	$ 190,676	$ 186,834
Capital commitments due to pipeline operators	933,666	—	—	—	—	—
Senior Notes due 2009[1]	—	—	—	—	—	125,000,000
Senior Notes due 2012[1]	—	—	—	—	—	200,000,000
Credit Facility which expires in October 2005[2]	—	—	—	—	—	—
	$3,124,029	$2,191,495	$ 523,755	$ 190,676	$ 190,676	$325,186,834

[1]These amounts do not include the interest obligation, which is paid semiannually.

[2]The repayment of the credit facility is based upon the zero balance at December 31, 2002. This amount excludes $0.8 million of a standby letter of credit issued under this facility.

[3]These amounts exclude asset retirement obligations, as accounted for under SFAS No. 143 "Accounting for Asset Retirement Obligations." We adopted this statement on January 1, 2003, and recorded a liability of $8.9 million. This standard required us to record a liability for the fair value of its dismantlement and abandonment costs, excluding salvage values.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and will likely continue to be volatile in the future. Worldwide supply disruptions, such as the reduction in crude oil production from Venezuela, together with perceived risks such as the threat of war between the United States and Iraq, along with other factors, have caused the price of oil to increase significantly in the first quarter of 2003 when compared to historical prices. Other factors such as actions taken by OPEC, worldwide economic conditions, and weather conditions can cause wide fluctuations in the price of oil. Natural gas prices have also increased significantly in the first quarter of 2003 when compared to 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 wide fluctuations in the price of natural gas. All of the above factors are beyond our control.

Liquidity and Capital Resources

During 2002, we principally relied upon internally generated cash flows of $71.6 million, net proceeds from the issuance of long-term debt of $195.0 million, and net proceeds from our public stock offering of $30.5 million, less the repayment of bank borrowings of $134.0 million, to fund capital expenditures of $155.2 million. During 2001, we relied both upon internally generated cash flows of $139.9 million and upon additional borrowings from our bank credit facility of $123.4 million to fund capital expenditures of $275.1 million.

Net Cash Provided by Operating Activities. In 2002, net cash provided by our operating activities decreased by 49% to $71.6 million, as compared to $139.9 million in 2001 and $128.2 million in 2000. The 2002 decrease of $68.3 million was primarily due to a reduction of oil and gas sales of $40.0 million due to lower commodity prices and to an increase in interest of $10.6 million due to the higher debt balances and interest rates in 2002. The 2001 increase of $11.7 million was primarily due to a $14.0 million reduction in working capital as oil and gas sales receivables decreased in 2001 along with a reduction in interest expense of $3.3 million. These increases in cash flow were offset by an $8.0 million reduction of oil and gas sales, a $7.5 million increase in oil and gas production costs, and a $2.6 million increase in general and administrative expense.

Existing Credit Facilities. At December 31, 2002, we had no outstanding borrowings under our credit facility. Our credit facility at year-end 2002 consisted of a $300.0 million revolving line of credit with a $195.0 million borrowing base. The borrowing base is re-determined at least every six months and was reconfirmed by our bank group in November 2002 with the $195.0 million borrowing base. Our revolving credit facility includes, among other restrictions, requirements as to maintenance of certain minimum financial ratios (principally pertaining to working capital, debt, and equity ratios) and limitations on incurring other debt. We are in compliance with the provisions of this agreement. The credit facility extends until October 2005. At December 31, 2001, we had $134.0 million in outstanding borrowings under this facility.

Working Capital. Our working capital increased from a deficit of $36.5 million at December 31, 2001, to a deficit of $17.1 million at December 31, 2002. The increase was primarily due to reductions in payables to partnerships related to December 2001 property sales.

Capital Expenditures. In 2002, our capital expenditures of approximately $155.2 million included:

New Zealand activities of $95.2 million as follows:

- $56.1 million, or 36%, on producing properties acquisitions, with approximately $51.7 million spent on the TAWN acquisition and the remainder for the cash portion of our Bligh and Antrim acquisitions;
- $12.6 million, or 8%, on developmental drilling to further delineate the Rimu and Kauri areas;
- $10.6 million, or 7%, on gas processing plants, principally the Rimu Production Station;
- $10.3 million, or 7%, for exploratory drilling in the Rimu and Kauri areas;
- $5.2 million, or 3%, on prospect costs, principally seismic and geological costs;
- $0.4 million, or less than 1%, for fixed assets, principally computers and office furniture and fixtures.

Domestic activities of $60.0 million as follows:

- $34.4 million, or 22%, on developmental drilling;
- $11.1 million, or 7%, on domestic prospect costs, principally leasehold, seismic, and geological costs;
- $8.3 million, or 5%, on exploratory drilling;
- $2.3 million, or 1%, for producing property acquisitions, including the purchase of property interests from partnerships managed by us;
- $2.0 million, or 1%, on gas processing plants in the Brookeland and Masters Creek areas;
- $1.1 million, or less than 1% on field compression facilities; and
- $0.8 million, or less than 1%, for fixed assets.

In 2002, we participated in drilling 23 domestic development wells and seven domestic exploratory wells, of which 17 development wells and three exploratory wells were successful. In New Zealand three development wells and three exploratory wells were drilled. One of the development wells and one of the exploratory wells were dry.

We currently plan to spend $115 to $130 million in total capital expenditures in 2003, excluding acquisition costs and net of approximately $5 million to $15 million in non-core property dispositions. The budget for 2003 is largely dependent upon performance and pricing during the year. Domestic activities account for 85% of budgeted spending, primarily in the Lake Washington Area.

We believe that the anticipated internally generated cash flows for 2003, together with bank borrowings under our credit facility, will be sufficient to finance the costs associated with our currently budgeted 2003 capital expenditures. If other producing property acquisitions become attractive during 2003, we will explore the use of debt and/or equity offerings to fund such activity.

Our capital expenditures were approximately $275.1 million in 2001 and $173.3 million in 2000. During 2000, we used cash flows from operating activities of $128.2 million to fund capital expenditures of $173.3 million, along with part of the remaining net proceeds from our third quarter 1999 issuance of Senior Notes and common stock. During 2001, we relied both upon internally generated cash flows of $139.9 million and upon additional borrowings of $123.4 million from our bank credit facility to fund capital expenditures of $275.1 million. Our capital expenditures in 2001 included:

Domestic activities of $224.3 million as follows:

- $120.6 million, or 44%, on developmental drilling;
- $40.5 million, or 15%, for producing property acquisitions, with approximately $32.6 million spent on the Lake Washington acquisition and the remainder for the purchase of property interests from partnerships managed by us;
- $36.4 million, or 13%, on exploratory drilling;
- $25.3 million, or 9%, on domestic prospect costs, principally leasehold, seismic, and geological costs;

- $1.1 million, or less than 1%, for fixed assets;
- $0.3 million on field compression facilities; and
- $0.1 million on gas processing plants in the Brookeland and Masters Creek areas.

New Zealand activities of $50.8 million as follows:

- $19.0 million, or 7%, on developmental drilling to further delineate the Rimu and Kauri areas;
- $17.9 million, or 7%, on the Rimu Production Station;
- $7.2 million, or 3%, for exploratory drilling in the Rimu and Kauri areas;
- $5.5 million, or 2%, on prospect costs, principally seismic and geological costs;
- $0.8 million, or less than 1%, on producing property acquisition evaluation costs related to our TAWN acquisition; and
- $0.4 million for fixed assets, principally computers and office furniture and fixtures.

In 2001, we participated in drilling 40 development wells and 13 exploratory wells, of which 38 development wells and six exploratory wells were successful. Four of the development wells were drilled in New Zealand to delineate the Rimu and Kauri areas, two of which were successful. Two of the exploratory wells were drilled in New Zealand; one was unsuccessful and one was temporarily abandoned.

Results of Operations

Revenues. Our revenues in 2002 decreased by 18% compared to revenues in 2001 due primarily to decreases in oil and gas prices. Partially offsetting the decrease in commodity prices received was the effect of an increase in production from our New Zealand and Lake Washington areas.

Oil and gas sales revenues in 2002 decreased by 22%, or $40.0 million, from the level of those revenues for 2001 even though our net sales volumes in 2002 increased by 11%, or 5.0 Bcfe, over net sales volumes in 2001. Average prices received for oil decreased to $20.88 per Bbl in 2002 from $22.64 per Bbl in 2001. Average gas prices received decreased to $2.30 per Mcf in 2002 from $4.23 per Mcf in 2001. The increase in production during the 2002 period is primarily from our New Zealand and Lake Washington areas.

In 2002, our $40.0 million decrease in oil and gas sales resulted from:

- Price variances that had a $59.0 million unfavorable impact on sales, of which $6.6 million was attributable to the 8% decrease in average oil prices received and $52.4 million was attributable to the 46% decrease in average gas prices received; and
- Volume variances that had a $19.0 million favorable impact on sales, with $16.2 million of increases coming from the 715,000 Bbl increase in oil sales volumes, and $2.8 million of the increases from the 0.7 Bcf increase in gas sales volumes.

Revenues in 2001 decreased by 4% compared to 2000 revenues. In 2001, oil and gas sales revenues decreased by 4%, or $8.0 million, from the level of those revenues in 2000 even though our net sales volumes in 2001 increased by 6%, or 2.4 Bcfe, over net sales volumes in 2000. Average prices received for oil decreased to $22.64 per Bbl in 2001 from $29.35 per Bbl in 2000. Average gas prices received decreased slightly to $4.23 per Mcf in 2001 from $4.24 per Mcf in 2000.

In 2001, our $8.0 million decrease in oil and gas sales resulted from:

- Price variances that had a $20.6 million unfavorable impact on sales, of which $20.5 million was attributable to the 23% decrease in average oil prices received and $0.1 million was attributable to the slight decrease in average gas prices received; and
- Volume variances that had a $12.6 million favorable impact on sales, with an increase of $17.1 million from the 583,000 Bbl increase in oil sales volumes offset somewhat by a decrease of $4.5 million from the 1.1 Bcf decrease in gas sales volumes.

The following table provides additional information regarding the changes in the sources of our oil and gas sales and volumes from our four domestic core areas and New Zealand:

	Revenues (in millions)		Net Sales Volume (Bcfe)	
Area	2002	2001	2002	2001
AWP Olmos	$ 33.1	$ 56.1	10.9	13.0
Brookeland	11.9	25.1	4.1	6.5
Lake Washington	18.5	4.6	4.4	1.2
Masters Creek	32.3	62.3	9.7	15.3
Other	16.3	31.3	5.2	8.3
Total Domestic	$ 112.1	$ 179.4	34.3	44.3
Rimu/Kauri	4.0	1.8	1.5	0.5
TAWN	25.1	—	14.0	—
Total New Zealand	$ 29.1	$ 1.8	15.5	0.5
Total	$ 141.2	$ 181.2	49.8	44.8

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

	Net Sales Volume			Average Sales Price	
	Oil and Condensate (MBbl)	Gas (Bcf)	Combined (Bcfe)	Oil and Condensate (Bbl)	Gas (Mcf)
2000:					
First Qtr.	653	6.6	10.6	$27.35	$2.93
Second Qtr.	650	6.9	10.8	$27.55	$3.99
Third Qtr.	591	7.0	10.5	$30.68	$4.39
Fourth Qtr.	578	7.0	10.5	$32.26	$5.55
	2,472	27.5	42.4	$29.35	$4.24
2001:					
First Qtr.	603	6.7	10.3	$27.63	$6.86
Second Qtr.	691	7.1	11.3	$26.05	$4.66
Third Qtr.	813	6.8	11.7	$23.76	$2.94
Fourth Qtr.	948	5.9	11.5	$16.02	$2.21
	3,055	26.5	44.8	$22.64	$4.23
2002:					
First Qtr.	944	6.6	12.3	$16.10	$1.72
Second Qtr.	1,002	6.7	12.7	$20.98	$2.60
Third Qtr.	908	6.7	12.2	$23.05	$2.32
Fourth Qtr.	916	7.1	12.6	$23.55	$2.55
	3,770	27.1	49.8	$20.88	$2.30

In the table above, for 2002, natural gas liquids have been combined with oil and condensate for reporting purposes. The natural gas liquids production for 2002 was 1,174 MBbls, at an average price of $12.82 per barrel.

In March 2002, we received $7.5 million for our interest in the Samburg project located in Western Siberia, Russia as a result of the sale by a third party of its ownership in a Russia joint stock company that owned and operated the field. Although the proceeds from sales of oil and gas properties are generally treated as a reduction of oil and gas property costs, because we had previously charged to expense all $10.8 million of cumulative costs relating to our Russian activities, this cash payment, net of transaction expenses, resulted in recognition of a $7.3 million non-recurring gain on asset disposition in the first quarter of 2002. This activity was recorded in "Gain on asset disposition" in the accompanying consolidated statement of income.

During 2002, we recognized net losses of $191,701 relating to our derivative activities, as compared to net gains of $1,173,094 in 2001. In 2002, $7,889 of the losses were unrealized, while $16,784 of losses recognized in 2001 were unrealized. This activity is recorded in "Price-risk management and other, net" on the accompanying income statement.

Revenues from our oil and gas sales comprised 94% of total revenues for 2002 and 99% of total revenues for both 2001 and 2000. Natural gas production made up 55% of our production volumes in 2002, 59% in 2001, and 65% in 2000.

Costs and Expenses. Our expenses in 2002 decreased $86.4 million, or 40%, compared to 2001 expenses. The majority of the decrease was due to the $98.9 million non-cash write-down of domestic oil and gas properties in 2001, offset by increases in operating costs in 2002 related to our increased activities in New Zealand. Our expenses in 2001 increased by $119.5 million, or 121%, compared to 2000 expenses. The majority of this increase was due to the non-cash write-down of domestic oil and gas properties in 2001.

Our general and administrative expenses, net in 2002 increased $2.4 million, or 29%, from the level of such expenses in 2001, while 2001 general and administrative expenses increased $2.6 million, or 47%, over 2000 levels. These increases reflect additional costs needed to run our increased activities in New Zealand, along with a reduction in reimbursement from partnerships we manage as these partnerships have liquidated. Our general and administrative expenses per Mcfe produced increased to $0.21 per Mcfe in 2002 from $0.18 per Mcfe in 2001 and $0.13 per Mcfe in 2000. The portion of supervision fees netted from general and administrative expenses was $3.0 million for 2002, $3.1 million for 2001, and $3.4 million for 2000.

Depreciation, depletion, and amortization of our assets, or DD&A, decreased $3.3 million, or 6%, in 2002 from 2001 levels, while 2001 DD&A increased $11.7 million, or 25%, from 2000 levels. Domestically, DD&A decreased $15.6 million due to decreased production in the 2002 period, the domestic non-cash write-down of oil and gas properties in the fourth quarter of 2001 that decreased our depletable oil and gas property base, and higher reserve volumes that were added primarily though our Lake Washington activities. In New Zealand, our production and the depletable oil and gas property base both increased in the 2002 period due primarily to the TAWN acquisition. The May 2002 commissioning of our Rimu Production Station also increased the depletable oil and gas property base. In 2001, the increase domestically was primarily due to additional dollars spent to add to our reserves and increased associated costs in an environment where demand for oil and gas services had increased compared to 2000, along with a 6% increase in production. Our DD&A rate per Mcfe of production was $1.13 in 2002, $1.33 in 2001, and $1.13 in 2000, reflecting variations in per unit cost of reserves additions.

Our production costs per Mcfe produced were $0.83 in 2002, $0.82 in 2001, and $0.69 in 2000. The portion of supervision fees netted from production costs was $2.0 million for 2002, $3.1 million for 2001, and $3.4 million for 2000. Our production costs in 2002 increased $4.8 million, or 13%, over such expenses in 2001, while those expenses in 2001 increased $7.5 million, or 26%, over 2000 costs. Overall, production costs increased in 2002 as our New Zealand activities increased, offsetting the domestic production costs decrease which mainly was due to a decrease in production volumes. Approximately $1.7 million of the increase in production costs during 2001 was related to severance taxes. Severance taxes increased primarily from the expiration of certain specific well severance tax exemptions. The remainder of the 2001 increase reflected costs associated with new wells drilled and acquired and the related increase in costs in procuring such services in an environment where demand for oil and gas services has increased from the prior year.

Interest expense on our Senior Notes issued in July 1999, including amortization of debt issuance costs, totaled $13.2 million in 2002 and $13.1 million in both 2001 and 2000. Interest expense on our Senior Notes issued in April 2002, including amortization of debt issuance costs, totaled $13.5 million in 2002. Interest expense on our Convertible Notes due 2006, including amortization of debt issuance costs, totaled $7.4 million in 2000. Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $3.6 million in 2002, $5.8 million in 2001, and $0.7 million in 2000. The total interest cost in 2002 was $30.3 million, of which $7.0 million was capitalized. The total interest cost in 2001 was $18.9 million, of which $6.3 million was capitalized. The 2000 total interest cost was $21.2 million, of which $5.2 million was capitalized. We capitalize that portion of interest related to our exploration, partnership, and foreign business development activities. The increase in interest expense in 2002 was attributed to the replacement of our bank borrowings in April 2002 with the Senior Notes that carry a higher interest rate. The decrease in total interest expense in 2001 was attributed to the conversion and extinguishment of our Convertible Notes in December 2000 and the increase in capitalized interest, partially offset by the increase in interest paid on our credit facility.

In the fourth quarter of 2001, we recognized a domestic non-cash write-down of oil and gas properties, as discussed in Note 1 to the Consolidated Financial Statements. Lower prices for both oil and natural gas at December 31, 2001, necessitated a pre-tax domestic full-cost ceiling write-down of $98.9 million, or $63.5 million after tax. In addition to this domestic ceiling write-down, we also expensed $2.1 million of charges in the fourth quarter of 2001 for certain delinquent accounts receivable, the majority of which were related to gas sold to Enron, and a write-off of debt issuance costs for a planned offering that was cancelled based upon market conditions following the events of September 11, 2001.

As discussed in Note 1 to the Consolidated Financial Statements, we adopted SFAS No. 133, amended by SFAS No. 137 and SFAS No. 138, on January 1, 2001. Our adoption of SFAS No. 133 resulted in a one-time net of taxes charge of $392,868, which is recorded as a "Cumulative Effect of Change in Accounting Principle" on the 2001 consolidated statement of income.

In the fourth quarter of 2000, we recorded a $0.6 million loss on the early extinguishment of debt (net of taxes), as discussed in Note 4 to the financial statements. We called our Convertible Notes for redemption effective December 26, 2000. Holders of approximately $100.0 million of the Convertible Notes elected to convert their notes into shares of our common stock. Holders of the remaining $15.0 million of the Convertible Notes elected to redeem their notes for cash plus accrued interest. This cash redemption resulted in this extraordinary item.

Net Income (Loss). Our net income in 2002 of $11.9 million was 153% higher and basic earnings per share ("Basic EPS") of $0.45 was 150% higher than our 2001 net loss of $(22.3) million and basic loss per share ("Basic EPS") of $(0.90). Our earnings per diluted share in 2002 of $0.45 was 150% higher than our 2001 loss per diluted share of $(0.90). These amounts increased in 2002 due to overall lower costs, as a non-cash write-down of oil and gas properties occurred in 2001 and not 2002, offset somewhat by lower revenue in 2002.

Our net loss in 2001 of $(22.3) million was 138% lower and basic loss per share of $(0.90) was 132% lower than our 2000 net income of $59.2 million and basic earnings per share of $2.79. Our earnings per diluted share in 2001 of $(0.90) was 136% lower than our 2000 earnings per diluted share of $2.51. These decreases reflected the effect of $101.0 million in charges in 2001 as described above.

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 requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from estimates.

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. Under the full-cost method of accounting, such costs may be incurred both prior to or 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 2002, 2001, and 2000, such internal costs capitalized totaled $10.7 million, $11.6 million, and $10.3 million, respectively. Interest costs related to unproved properties are also capitalized to unproved oil and gas properties. Interest not capitalized and general and administrative costs related to production and general 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.

Future development, site restoration, and dismantlement and abandonment costs, net of salvage values, 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 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, site restoration, and dismantlement and abandonment costs, net of salvage value, 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. This calculation is done on a country-by-country basis. Furniture, fixtures and other equipment are depreciated by the straight-line method at rates based on the estimated useful lives of the property. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

The cost of unproved properties not being amortized is assessed quarterly, on a country-by-country basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, foreign currency exchange rates, the political stability in the countries in which we have an investment, 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, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using unhedged period-end prices, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects ("Ceiling Test"). This calculation is done on a country-by-country basis for those countries with proved reserves.

The calculation of the Ceiling Test and provision for depreciation, depletion, and amortization 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 estimate. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered.

In the fourth quarter of 2001, as a result of low oil and gas prices at December 31, 2001, we reported a non-cash write-down on a before-tax basis of $98.9 million ($63.5 million after tax) on our domestic properties. We had no write-down on our New Zealand properties.

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 additional non-cash write-downs of oil and gas properties could occur in the future.

Price-Risk Management Activities. We follow SFAS No. 133 which requires that changes in the derivative's fair value be 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) be reported in the balance sheet as either an asset or liability measured at its fair value. Special hedge accounting for qualifying hedges would allow the gains and losses on derivatives to offset related results on the hedged item in the income statements and would require that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting.

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 protection price floors and collars. We adopted SFAS No. 133 effective January 1, 2001. Accordingly, we marked our open contracts at December 31, 2000, to fair value at that date, resulting in a one-time net of taxes charge of $392,868, which was recorded as a Cumulative Effect of Change in Accounting Principle. During 2002 and 2001, we recognized net losses of $191,701 and net gains of $1,173,094 relating to our derivative activities. Approximately $7,889 of the losses recognized in 2002 were unrealized as the contracts were still open, while $16,784 of losses recognized in the comparative 2001 period were unrealized. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. At December 31, 2002, we had recorded $178,053, net of taxes of $100,155, of derivative losses in "Other comprehensive loss" on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our collar transactions that were qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for 2002 was not material. We expect to reclassify all amounts held in "Other comprehensive loss" into the statement of income within the next six months.

As of December 31, 2002, we had entered into the cash flow hedge commodity derivative instruments set forth in the table below for our domestic oil and natural gas production for portions of 2003. When we entered into the following transactions they were designated as a hedge of the variability in cash flows associated with the forecasted sale of our oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and qualifies as a cash flow hedge, to the extent that the hedge is effective, are initially recorded in Other Comprehensive Income (Loss). When the hedged transactions are recorded upon the actual sale of oil and natural gas, these gains or losses are transferred from Other Comprehensive Income (Loss) and recorded in "Price-risk management and other, net" on the statement of income. The fair value of our derivatives are computed using the Black-Scholes option pricing model and are periodically verified against quotes from brokers. The fair value of these instruments is recognized on the balance sheet, in "Accounts payable and accrued liabilities," at December 31, 2002.

Crude Oil - Cash Flow Hedges

Period and Type of Contract	Volume in Bbls (000s)	Collars: Floors Weighted Average	Collars: Ceilings Weighted Average	December 31, 2002 Fair Value (000s)
January 2003 - June 2003				
Participating Collar Contracts	360	$21.00		$76
	144		$30.35	$(256)
Total				$(180)

Natural Gas - Cash Flow Hedges

Period and Type of Contract	Volume in Mmbtu (000s)	Collars: Floors Weighted Average	Collars: Ceilings Weighted Average	December 31, 2002 Fair Value (000s)
January 2003 - June 2003				
Participating Collar Contracts	1,900	$3.00		$12
	760		$5.27	$(122)
Total				$(110)

In January and February 2003, we entered into natural gas "floors" financial transactions covering contract periods April 2003 to October 2003. Notional volumes are 450,000 MMBtu per month at a weighted average floor price of $4.36 per MMBtu. In January 2003, we entered into crude oil "floors" financial transactions covering the contract periods of February to April 2003. Notional volumes are 625,000 barrels over the three-month period with a weighted average floor price of $26.39 per barrel. Also in February 2003, we entered into a crude oil "collar" financial transaction covering the contract period April 2003 to June 2003.

Notional volumes are 120,000 barrels over the three-month period with a weighted average floor price of $25.25 per barrel and 48,000 barrels over the three-month period with a weighted average ceiling price of $33.08 per barrel.

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

Related-Party Transactions

We have been the operator of a number of properties owned by our affiliated limited partnerships and, accordingly, charge these entities operating fees. The operating fees charged to the partnerships in 2002, 2001, and 2000 totaled approximately $300,000, $925,000, and $1,775,000, respectively, and are recorded as reductions of general and administrative expense and oil and gas production expense. We also have been reimbursed for direct, administrative, and overhead costs incurred in conducting the business of the limited partnerships, which totaled approximately $973,000, $3,140,000, and $4,465,000 in 2002, 2001, and 2000, respectively. In partnerships in which the limited partners voted to sell their remaining properties and liquidate their limited partnerships, we also have been reimbursed for direct, administrative, and overhead costs incurred in the disposition of such properties, which costs totaled approximately $510,000, $2,360,000, and $1,220,000 in 2002, 2001, and 2000, respectively.

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 and 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; 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 herein and set forth from time to time in our other public reports, filings, and public statements. Also, because of the volatility in oil and gas prices and other factors, interim results are not necessarily indicative of those for a full year.

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 discussed above, and such volatility is expected to continue.

Our price-risk program permits the utilization of agreements and financial instruments (such as futures, forward and options contracts, and swaps) 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 February 28, 2003, we had in place price floors in effect through the October 2003 contract month for natural gas and April 2003 for crude oil. The natural gas price floors cover notional volumes of 3,150,000 MMBtu, with a weighted average floor price of $4.36 per MMBtu. The crude oil price floors cover notional volumes of 400,000 barrels of oil, with a weighted average floor price of $26.13 per barrel.
- *Participating Collars* – At February 28, 2003, we had in place certain "collar" financial transactions in effect through the June 2003 contract month. The natural gas collars cover notional volumes of 1,100,000 MMBtu, with a floor price of $3.00 per MMBtu and ceiling prices ranging from $4.75 per MMBtu to $6.00 per MMBtu, plus 60% participation by us in prices realized above the ceiling. The crude oil collars cover notional volumes of 360,000 barrels of oil, with floor prices ranging from $21.00 to $26.00 per barrel and ceiling prices ranging from $29.04 to $35.05 per barrel, plus 60% participation by us in prices realized above these ceilings.
- *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 have a fixed interest rate, so consequently we are not exposed to cash flow risk from market interest rate changes on our Senior Notes. At December 31, 2002, we had no outstanding borrowings under our credit facility, which is subject to floating rates and therefore susceptible to interest rate fluctuations. The result of a 10% fluctuation in the bank's base rate would constitute 43 basis points and would not impact 2003 cash flows based on this same level of borrowing.

Financial Instruments & Debt Maturities. Our financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2002 and 2001, and were determined based upon interest rates currently available to us for borrowings with similar terms. Based on quoted market prices as of the respective dates, the fair value of our Senior Notes due 2009 was $129.0 million at December 31, 2002, and $126.5 million at December 31, 2001. Based upon quoted market prices as of the respective dates, the fair value of our Senior Notes due 2012 was $189.2 million at December 31, 2002. Our credit facility with the banks expires October 1, 2005. Our $125.0 million Senior Notes mature on August 1, 2009. Our $200.0 million Senior Notes mature on May 1, 2012.

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 dependant 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 materially affect our revenues.

Report of Independent Auditors

To the Stockholders and Board of Directors of Swift Energy Company:

We have audited the accompanying consolidated balance sheet of Swift Energy Company and subsidiaries as of December 31,2002, and the related consolidated statements of income, stockholders' equity and cash flows for the year then ended. 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 audit. The consolidated financial statements of Swift Energy Company and subsidiaries as of December 31, 2001, and for each of the two years in the period ended December 31, 2001, were audited by other auditors who have ceased operations and whose report dated February 18, 2002, expressed an unqualified opinion on those statements.

We conducted our audit in accordance with auditing standards generally accepted in the 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 audit provides a reasonable basis for our opinion.

In our opinion, the 2002 financial statements referred to above present fairly, in all material respects, the consolidated financial position of Swift Energy Company and subsidiaries at December 31, 2002, and the consolidated results of their operations and their cash flows for the year then ended, in conformity with accounting principles generally accepted in the United States.

Ernst & Young LLP

ERNST & YOUNG LLP

Houston, Texas
February 10, 2003

Report of Independent Public Accountants

To the Stockholders and Board of Directors of Swift Energy Company:

We have audited the accompanying consolidated balance sheets of Swift Energy Company (a Texas corporation) and subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2001. 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 auditing standards generally accepted in the 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 financial position of Swift Energy Company and subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP

Houston, Texas
February 18, 2002

NOTE: This is a copy of the report previously issued by Arthur Andersen LLP and has not been reissued.

Consolidated Balance Sheets

Swift Energy Company and Subsidiaries

	December 31, 2002	December 31, 2001
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 3,816,107	$ 2,149,086
Accounts receivable—		
Oil and gas sales	17,360,716	14,215,189
Associated limited partnerships and joint ventures	191,964	6,259,604
Joint interest owners	3,364,846	11,467,461
Other current assets	5,034,566	2,661,640
Total Current Assets	29,768,199	36,752,980
Property and Equipment:		
Oil and gas, using full-cost accounting		
Proved properties	1,150,633,802	974,698,428
Unproved properties	69,603,481	95,943,163
	1,220,237,283	1,070,641,591
Furniture, fixtures, and other equipment	9,595,944	8,706,414
	1,229,833,227	1,079,348,005
Less — Accumulated depreciation, depletion, and amortization	(504,323,773)	(448,139,334)
	725,509,454	631,208,671
Other Assets:		
Deferred income taxes	2,680,585	—
Deferred charges	9,047,621	3,723,182
	11,728,206	3,723,182
	$ 767,005,859	$ 671,684,833
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 43,028,708	$ 38,884,380
Payable to associated limited partnerships	91,126	26,573,490
Undistributed oil and gas revenues	3,764,350	7,787,465
Total Current Liabilities	46,884,184	73,245,335
Long-Term Debt	324,271,973	258,197,128
Deferred Income Taxes	30,776,518	27,589,650
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, 27,811,632 and 25,634,598 shares issued, and 27,201,509 and 24,795,564 shares outstanding, respectively	278,116	256,346
Additional paid-in capital	333,543,471	296,172,820
Treasury stock held, at cost, 610,123 and 839,034 shares, respectively	(8,749,922)	(12,032,791)
Retained earnings	40,179,572	28,256,345
Accumulated other comprehensive loss, net of income tax	(178,053)	—
	365,073,184	312,652,720
	$ 767,005,859	$ 671,684,833

See accompanying Notes to Consolidated Financial Statements.

Consolidated Statements of Income

Swift Energy Company and Subsidiaries

	Year Ended December 31, 2002	2001	2000
Revenues:			
Oil and gas sales	$141,195,713	$181,184,635	$189,138,947
Fees from limited partnerships and joint ventures	67,173	427,583	331,497
Interest income	263,738	49,281	1,339,386
Gain on asset disposition	7,332,668	—	—
Price-risk management and other, net	1,110,519	2,145,991	815,116
	149,969,811	183,807,490	191,624,946
Costs and Expenses:			
General and administrative, net	10,564,849	8,186,654	5,585,487
Depreciation, depletion, and amortization	56,224,392	59,502,040	47,771,393
Oil and gas production	41,497,312	36,719,609	29,220,315
Interest expense, net	23,274,969	12,627,022	15,968,405
Other expenses	—	2,102,251	—
Write-down of oil and gas properties	—	98,862,247	—
	131,561,522	217,999,823	98,545,600
Income (Loss) Before Income Taxes, Extraordinary Item and Change in Accounting Principle	18,408,289	(34,192,333)	93,079,346
Provision (Benefit) for Income Taxes	6,485,062	(12,237,436)	33,265,480
Income (Loss) Before Extraordinary Item and Change in Accounting Principle	$ 11,923,227	$ (21,954,897)	$ 59,813,866
Extraordinary Loss on Early Extinguishment of Debt (net of taxes)	—	—	629,858
Cumulative Effect of Change in Accounting Principle (net of taxes)	—	392,868	—
Net Income (Loss)	$ 11,923,227	$ (22,347,765)	$ 59,184,008
Per Share Amounts—			
Basic: Income (Loss) Before Extraordinary Item and Change in Accounting Principle	$ 0.45	$ (0.89)	$ 2.82
Extraordinary Loss	—	—	(0.03)
Change in Accounting Principle	—	(0.01)	—
Net Income (Loss)	$ 0.45	$ (0.90)	$ 2.79
Diluted: Income (Loss) Before Extraordinary Item and Change in Accounting Principle	$ 0.45	$ (0.89)	$ 2.53
Extraordinary Loss	—	—	(0.02)
Change in Accounting Principle	—	(0.01)	—
Net Income (Loss)	$ 0.45	$ (0.90)	$ 2.51
Weighted Average Shares Outstanding	26,382,906	24,732,099	21,244,684

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	Retained Earnings (Deficit)	Accumulated Other Comprehensive Loss	Total
Balance, December 31, 1999	$ 216,832	$ 191,092,851	$ (12,325,668)	$ (8,579,898)	$ —	$ 170,404,117
Stock issued for benefit plans (46,632 shares)	310	297,060	224,469	—	—	521,839
Stock options exercised (543,450 shares)	5,434	4,316,446	—	—	—	4,321,880
Employee stock purchase plan (29,889 shares)	299	297,414	—	—	—	297,713
Subordinated notes conversion (3,164,644 shares)	31,646	97,392,952	—	—	—	97,424,598
Comprehensive income:						
Net income	—	—	—	59,184,008	—	59,184,008
Total comprehensive income	—	—	—	—	—	59,184,008
Balance, December 31, 2000	$ 254,521	$ 293,396,723	$ (12,101,199)	$ 50,604,110	$ —	$ 332,154,155
Stock issued for benefit plans (11,945 shares)	72	354,973	68,408	—	—	423,453
Stock options exercised (152,915 shares)	1,529	1,942,634	—	—	—	1,944,163
Employee stock purchase plan (22,360 shares)	224	478,490	—	—	—	478,714
Comprehensive loss:						
Net loss	—	—	—	(22,347,765)	—	(22,347,765)
Total comprehensive loss	—	—	—	—	—	(22,347,765)
Balance, December 31, 2001	$ 256,346	$ 296,172,820	$ (12,032,791)	$ 28,256,345	$ —	$ 312,652,720
Stock issued for benefit plans (38,149 shares)	292	617,960	127,795	—	—	746,047
Stock options exercised (112,995 shares)	1,130	1,206,413	—	—	—	1,207,543
Public stock offering (1,725,000 shares)	17,250	30,465,809	—	—	—	30,483,059
Employee stock purchase plan (9,801 shares)	98	122,343	—	—	—	122,441
Stock issued in acquisitions (520,000 shares)	3,000	4,958,126	3,155,074	—	—	8,116,200
Comprehensive income:						
Net income	—	—	—	11,923,227	—	11,923,227
Change in fair value of cash flow hedges, net of income tax	—	—	—	—	(178,053)	(178,053)
Total comprehensive income	—	—	—	—	—	11,745,174
Balance, December 31, 2002	$ 278,116	$ 333,543,471	$ (8,749,922)	$ 40,179,572	$ (178,053)	$ 365,073,184

[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, 2002	2001	2000
Cash Flows from Operating Activities:			
Net income (loss)	$ 11,923,227	$ (22,347,765)	$ 59,184,008
Adjustments to reconcile net income (loss) to net cash provided by operating activities—			
Depreciation, depletion, and amortization	56,224,392	59,502,040	47,771,393
Write-down of oil and gas properties	—	98,862,247	—
Deferred income taxes	6,482,724	(12,555,618)	33,413,626
Gain on asset disposition	(7,332,668)	—	—
Deferred revenue amortization related to production payment	—	—	(587,629)
Other	270,770	509,973	1,075,848
Change in assets and liabilities—			
(Increase) decrease in accounts receivable, excluding income taxes receivable	283,419	16,207,377	(14,308,274)
Increase in accounts payable and accrued liabilities	3,174,450	12,984	1,601,042
(Increase) decrease in income taxes receivable	600,000	(306,983)	47,213
Net Cash Provided by Operating Activities	71,626,314	139,884,255	128,197,227
Cash Flows from Investing Activities:			
Additions to property and equipment	(155,233,923)	(275,126,333)	(173,277,356)
Proceeds from the sale of property and equipment	13,256,674	9,274,440	3,844,375
Net cash received as operator of oil and gas properties	4,152,645	5,927,539	19,769,213
Net cash received (distributed) as operator of partnerships and joint ventures	(23,241,501)	(3,574,601)	2,674,593
Other	(39,953)	(534,898)	(1,329)
Net Cash Used in Investing Activities	(161,106,058)	(264,033,853)	(146,990,504)
Cash Flows from Financing Activities:			
Proceeds from (payments of) long-term debt	200,000,000	—	(15,203,000)
Net proceeds from (payments of) bank borrowings	(134,000,000)	123,400,000	10,600,000
Net proceeds from issuances of common stock	31,409,200	1,633,508	2,697,561
Payments of debt issuance costs	(6,262,435)	(721,756)	—
Net Cash Provided by (Used in) Financing Activities	91,146,765	124,311,752	(1,905,439)
Net Increase (Decrease) in Cash and Cash Equivalents	$ 1,667,021	$ 162,154	$ (20,698,716)
Cash and Cash Equivalents at Beginning of Year	2,149,086	1,986,932	22,685,648
Cash and Cash Equivalents at End of Year	$ 3,816,107	$ 2,149,086	$ 1,986,932
Supplemental Disclosures of Cash Flows Information:			
Cash paid during year for interest, net of amounts capitalized	$ 19,189,822	$ 12,207,205	$ 15,528,280
Cash paid during year for income taxes	$ 2,500	$ 441,926	$ —
Non-Cash Financing Activity:			
Issuance of common stock in acquisitions	$ 8,116,200	$ —	$ —
Conversion of convertible notes to common stock	$ —	$ —	$ 99,797,000

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) and our wholly owned subsidiaries, which are engaged in the exploration, development, acquisition, and operation of oil and natural gas properties, with a focus on onshore and inland waters oil and natural gas reserves in Texas and Louisiana, as well as onshore oil and natural gas reserves in New Zealand. Our investments in associated oil and gas partnerships and joint ventures 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 consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the consolidated financial statements.

Use of Estimates. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from estimates.

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. Under the full-cost method of accounting, such costs may be incurred both prior to or 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 2002, 2001, and 2000, such internal costs capitalized totaled \$10.7 million, \$11.6 million, and \$10.3 million, respectively. Interest costs related to unproved properties are also capitalized to unproved oil and gas properties. Interest not capitalized and general and administrative costs related to production and general 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.

Future development, site restoration, and dismantlement and abandonment costs, net of salvage values, 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 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, site restoration, and dismantlement and abandonment costs, net of salvage value, 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. This calculation is done on a country-by-country basis. Furniture, fixtures and other equipment are depreciated by the straight-line method at rates based on the estimated useful lives of the property. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

The cost of unproved properties not being amortized is assessed quarterly, on a country-by-country basis, to determine whether such properties have been impaired. In determining whether such costs should be impaired, we evaluate current drilling results, lease expiration dates, current oil and gas industry conditions, international economic conditions, capital availability, foreign currency exchange rates, the political stability in the countries in which we have an investment, 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, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using unhedged period-end prices, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects ("Ceiling Test"). This calculation is done on a country-by-country basis for those countries with proved reserves.

The calculation of the Ceiling Test and provision for depreciation, depletion, and amortization 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 estimate. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered.

In the fourth quarter of 2001, as a result of low oil and gas prices at December 31, 2001, we reported a non-cash write-down on a before-tax basis of \$98.9 million (\$63.5 million after tax) on our domestic properties. We had no write-down on our New Zealand properties.

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 the Company's period-end prices used in the Ceiling Test, even if only for a short period, it is possible that additional non-cash write-downs of oil and gas properties could occur in the future.

Oil and Gas Revenues. Oil and gas revenues are recognized, as the product is delivered, using the entitlement method in which we recognize our ownership interest in production as revenue. If our sales exceed our ownership share of production, the differences are reported as deferred revenues. Natural gas balancing receivables are reported when our ownership share of production exceeds sales. As of December 31, 2002, we did not have any material natural gas imbalances.

Deferred Charges. Legal and accounting fees, underwriting fees, printing costs, and other direct expenses associated with the public offering in August 1999 of our 10.25% Senior Subordinated Notes (the "Senior Notes"), the September 2001 extension of our bank credit facility, and the public offering in April 2002 of our 9.375% Senior Subordinated Notes were capitalized and are amortized over the life of each of the respective note offerings and credit facility. The Convertible Notes were called for redemption effective December 26, 2000, and the balance of their unamortized issuance costs at that time of $3,046,181 was either transferred to the common stock equity accounts ($2,643,476) for the portion of the Convertible Notes converted into common stock at the election of those note holders or was recorded, net of taxes, as Extraordinary Loss on Early Extinguishment of Debt ($402,705) for the portion of the Convertible Notes redeemed for cash. The Senior Notes due 2009 mature on August 1, 2009, and the balance of their issuance costs at December 31, 2002, was $2,686,678, net of accumulated amortization of $814,764. The issuance costs associated with our revolving credit facility, which closed in September 2001, have been capitalized and are being amortized over the life of the facility. The balance of revolving credit facility issuance costs at December 31, 2002, was $986,957, net of accumulated amortization of $937,591. The Senior Notes due 2012 mature on May 1, 2012, and the balance of their issuance costs at December 31, 2002, was $5,373,986, net of accumulated amortization of $244,349.

Limited Partnerships and Joint Ventures. We formed 88 limited partnerships between 1984 and 1995 to acquire interests in producing oil and gas properties and 13 partnerships between 1993 and 1998 to drill for oil and gas. In all of these partnerships, Swift paid for varying percentages of the capital or front-end costs and continuing costs of the partnerships and, in return, received differing percentage ownership interests in the partnerships, along with reimbursement of costs and/or payment of certain fees. At year-end 2002, we continue to serve as managing general partner for six remaining drilling partnerships, and during fiscal 2002 less than 1% of our total oil and gas sales was attributable to our interests in those partnerships.

During 1997 and 1998, eight drilling partnerships formed between 1979 and 1985 and 21 of the production purchase partnerships sold their properties and were dissolved, in each case following a vote of the investors in the particular partnerships approving such liquidations. Between 1999 and 2001, the investors in all but six of the remaining partnerships voted to sell the partnerships' properties or their interests in the partnerships and dissolve. During 2001, seven drilling partnerships and two production purchase partnerships were dissolved. During 2002, an additional 65 production purchase partnerships were dissolved. The remaining six partnerships will continue to operate until their limited partners vote otherwise.

Price-Risk Management Activities. The Company follows SFAS No. 133 which requires that changes in the derivative's fair value be 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) be recorded in the balance sheet as either an asset or a liability measured at its fair value. Special hedge accounting for qualifying hedges would allow the gains and losses on derivatives to offset related results on the hedged item in the income statements and would require that a company formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS No. 133, as amended by SFAS No. 137 and SFAS No. 138, was adopted by us on January 1, 2001.

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 protection price floors and collars. Upon adoption of SFAS No. 133 on January 1, 2001, we recorded a net of taxes charge of $392,868, which is recorded as a Cumulative Effect of Change in Accounting Principle. During 2002 and 2001, we recognized net losses of $191,701 and net gains of $1,173,094, respectively, relating to our derivative activities. Approximately $7,889 of the losses recognized in 2002 were unrealized as the contracts were still open, while $16,784 of losses recognized in the comparative 2001 period were unrealized. This activity is recorded in "Price-risk management and other, net" on the accompanying statements of income. At December 31, 2002, the Company had recorded $178,053, net of taxes of $100,155, of derivative losses in "Other comprehensive loss" on the accompanying balance sheet. This amount represents the change in fair value for the effective portion of our collar transactions that were qualified as cash flow hedges. The ineffectiveness reported in "Price-risk management and other, net" for 2002 was not material. The Company expects to reclassify all amounts held in "Other comprehensive loss" into the statement of income within the next six months.

As of December 31, 2002, the Company had entered into certain "collar" financial transactions in effect through the June 2003 contract month. The natural gas collars cover notional volumes of 1,900,000 MMBtu for the price floors and 760,000 MMBtu for the price ceilings, with a weighted average floor price of $3.00 per MMBtu and a weighted average ceiling price of $5.27 per MMBtu. The crude oil collars cover notional volumes of 360,000 barrels for the price floors and 144,000 barrels for the price ceilings, with a weighted average floor price of $21.00 per barrel and a weighted average ceiling price of $30.35 per barrel. When the Company entered into the following transactions they were designated as a hedge of the variability in cash flows associated with the forecasted sale of its oil and natural gas production. Changes in the fair value of a hedge that is highly effective and is designated and qualifies as a cash flow hedge, to the extent that the hedge is effective, are initially recorded in Other Comprehensive Income (Loss). When the hedged transactions are recorded upon the actual sale of oil and natural gas, these gains or losses are transferred from Other Comprehensive Income (Loss) and recorded in "Price-risk management and other, net" on the income statement. The fair value of our derivatives are computed using the Black-

Scholes option pricing model and are periodically verified against quotes from brokers. At December 31, 2002, the fair value of the natural gas collars was a liability of $0.1 million and the fair value of our crude oil collars was a liability of $0.2 million. These instruments are recognized on the balance sheet in "Accounts payable and accrued liabilities" at December 31, 2002.

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 bases of assets and liabilities, given the provisions of the enacted tax laws.

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 monthly 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 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 2002, oil and gas sales to Eastex Crude Company were $25.4 million, or 18.0% of oil and gas sales, while sales to subsidiaries of Contact Energy in New Zealand were $14.6 million, or 10.3% of oil and gas sales. During 2001, oil and gas sales to subsidiaries of Eastex Crude Company were $31.6 million, or 18.1% of oil and gas sales, while sales to subsidiaries of Enron were $18.2 million, or 10.4% of oil and gas sales. During 2000, oil and gas sales to subsidiaries of Eastex Crude Company were $47.4 million, or 25.7% of our oil and gas sales, while sales to subsidiaries of PG&E Energy Trading Corporation were $21.2 million, or 11.5% of oil and gas sales. Beginning in December 2000, the subsidiaries of PG&E Energy Trading Corporation to which we made sales were sold to subsidiaries of El Paso Corporation. All receivables from PG&E were collected. During the fourth quarter of 2001, we wrote off $1.4 million due to uncollected receivables related to gas sold to Enron in November 2001. This amount is included in "Other expenses" on the Consolidated Statement of Income. We have discontinued sales of oil and gas to Enron and are selling that production to other purchasers.

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

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 nature of these short-term instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 2002 and 2001, and were determined based upon variable interest rates currently available to us for borrowings with similar terms. Based on quoted market prices as of the respective dates, the fair values of our Senior Notes due 2009 were $129.0 million and $126.5 million at December 31, 2002 and 2001, respectively. Based upon quoted market prices as of December 31, 2002, the fair value of our Senior Notes due 2012 was $189.2 million. The carrying value of our Senior Notes due 2009 was $124.3 million and $124.2 million at December 31, 2002 and 2001, respectively. The carrying value of our Senior Notes due 2012 was $200.0 million at December 31, 2002.

New Accounting Pronouncements. In June 2001, the Financial Accounting Standards Board 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 entity increases the carrying amount of the related long-lived asset. Over time, accretion of the liability is recognized each period, and the capitalized cost is depreciated 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 upon settlement. This standard will require us to record a liability for the fair value of our dismantlement and abandonment costs, excluding salvage values. The standard is effective for fiscal years beginning after June 15, 2002. The Company has completed its assessment of SFAS No. 143. At January 1, 2003, we estimate that the present value of our future Asset Retirement Obligation ("ARO") for oil and gas properties and related equipment is approximately $8.9 million. We estimate that the cumulative effect of change in accounting principle, due to the adoption of SFAS No. 143, will be a loss of $6.8 million, or a loss of $4.4 million net of taxes. This cumulative effect of change in accounting principle will be a non-cash charge to net income in the first quarter of 2003.

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. The calculation of diluted earnings per share ("Diluted EPS") for 2000 assumes conversion of our Convertible Notes as of the beginning of the respective periods and the elimination of the related after-tax interest expense. The calculation of diluted earnings per share for all periods assumes, as of the beginning of the period, exercise of stock options and warrants using the treasury stock method. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the 2002 and 2001 periods.

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, 2002, 2001, and 2000:

	2002			2001			2000		
	Net Income	Shares	Per Share Amount	Net Loss	Shares	Per Share Amount	Net Income	Shares	Per Share Amount
Basic EPS:									
Net Income (Loss) and Share Amounts...	$11,923,227	26,382,906	$ 0.45	$(22,347,765)	24,732,099	$(0.90)	$ 59,184,008	21,244,684	$ 2.79
Dilutive Securities:									
6.25% Convertible Notes	—	—		—	—		4,772,418	3,546,933	
Stock Options.....	—	372,700		—	—		—	713,112	
Diluted EPS:									
Net Income (Loss) and Assumed Share Conversions	$11,923,227	26,755,606	$ 0.45	$(22,347,765)	24,732,099	$(0.90)	$ 63,956,426	25,504,729	$ 2.51

3. Provision for Income Taxes

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

	Year Ended December 31,		
	2002	2001	2000
Current	$ 2,338	$ 114,611	$ (29,000)
Deferred	6,482,724	(12,352,047)	33,294,480
Total........	$ 6,485,062	$ (12,237,436)	$ 33,265,480

There are differences between income taxes computed using the federal statutory rate (35% for 2002, 2001, and 2000) and our effective income tax rates (35.2%, 35.8%, and 35.7% for 2002, 2001, and 2000, respectively), primarily as the result of state income taxes, foreign income taxes, and in 2002 a currency exchange rate gain on the net foreign deferred tax asset. New Zealand's statutory rate and effective tax rate are 33%. We have not computed any provision for U.S. taxes on the undistributed earnings of our New Zealand subsidiaries as management intends to permanently reinvest such earnings. The undistributed earnings of the New Zealand subsidiaries were $8,175,013 and $1,234,919 for 2002 and 2001, respectively. Upon distribution of these earnings 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 on the eventual remittance of these earnings. Presently, there are no foreign tax credits available to reduce the U.S. taxes on such amounts if repatriated. Reconciliations of income taxes computed using the statutory rate to the effective income tax rates are as follows:

	2002	2001	2000
Income taxes computed at U.S. statutory rate	$ 6,442,901	$ (11,967,317)	$ 32,577,772
State tax provisions, net of federal benefits	298,933	(279,875)	775,850
Effect of foreign operations	(163,500)	(24,698)	—
Currency translation gain on foreign tax asset	(208,688)	—	—
Other, net	115,416	34,454	(88,142)
Provision (benefit) for income taxes	$ 6,485,062	$ (12,237,436)	$ 33,265,480

The tax effects of temporary differences representing the net deferred tax liability (asset) at December 31, 2002 and 2001, were as follows:

	2002	2001
Long-term deferred tax assets:		
Alternative minimum tax credits (domestic)	$ (1,979,399)	$ (1,979,399)
Carryover items (domestic)	(51,174,237)	(18,877,969)
Acquired deferred tax asset (foreign)	(4,753,044)	—
Carryover items (foreign)	(19,494,129)	—
Total long-term deferred tax assets	(77,400,809)	(20,857,368)
Long-term deferred tax liabilities:		
US oil and gas properties	83,361,520	47,556,981
Foreign oil and gas properties	21,566,588	407,524
Other	568,634	482,513
Total long-term deferred tax liabilities	105,496,742	48,447,018
Net long-term deferred tax liabilities	$ 28,095,933	$ 27,589,650

The tax basis of the assets of Southern NZ on the acquisition date exceeded the cash purchase price paid by SENZ to acquire this entity. To account for the future tax benefits of this additional basis, SENZ recorded a deferred tax asset of $4,944,786. Additionally, the Company recognized a currency exchange rate gain, primarily attributable to this acquired asset, in the amount of $632,389. The asset is being amortized over the period in which the tax amortization is deducted. The remaining asset value at December 31, 2002, is $4,753,044, of which $950,609 will be amortized in 2003. The total foreign carryover asset amount is $19,494,129, of which $7,807,407 is expected to reverse in 2003. The asset is attributable to cumulative New Zealand net operating losses with a $U.S. equivalent value of $59,073,129 (using the December 31, 2002, exchange rate) multiplied by the New Zealand tax rate of 33%. These net operating losses include the costs of drilling oil and gas wells classified as exploratory. Under New Zealand tax rules, such costs are deductible at the time the well is drilled, but are "clawed back" into revenue if and when the well establishes commercial production. After the clawback, the costs are then amortized as development expenditures. This clawback is expected to occur in 2003, but should be absorbed by the cumulative excess of tax amortization over book depreciation, depletion, and amortization. New Zealand tax net operating losses do not expire.

At December 31, 2002, the Company had alternative minimum tax credits of $1,979,399 that carry forward indefinitely. These credits are available to reduce future regular tax liability to the extent they exceed the related tentative minimum tax otherwise due.

The domestic deferred tax carryover items are attributable to expected future tax benefits in the amounts of $43,290,193 for federal net operating losses, $1,291,637 for State of Louisiana net operating losses, $6,574,726 for capital losses, and other items totaling $17,681. At December 31, 2002, cumulative federal net operating losses were $124 million, which will expire between 2018 and 2022. Louisiana net operating losses total $37 million and will expire between 2013 and 2017.

The Company has not recorded any valuation allowance against the deferred tax assets attributable to net operating loss carryovers at December 31, 2002 and 2001, as management estimates that it is more likely than not that these assets will be fully utilized before they expire. Significant changes in estimates caused by changes in oil and gas prices, production levels, capital expenditures, and other variables could impact the Company's ability to utilize the carryover amounts.

In 2002 we recognized a capital loss of approximately $18.2 million as the result of the liquidation of our partnerships. This loss can only be utilized to offset capital gains and will expire in 2007. The Company plans to continue selling, in the ordinary course of business, a number of oil and gas properties over the next few years in order to optimize its portfolio of non-core oil and gas properties. To generate gains from these dispositions that can absorb the capital loss carryforward, the sales proceeds must exceed the Company's total investment in the properties before depreciation, depletion, and IDC deductions and amortization. Company management has identified several qualified properties to sell which have estimated current market values in excess of the total original costs. Management believes that it is more likely than not that the Company will fully utilize the capital loss carryover. If the Company is unable to complete the sale of these properties at the prices it has estimated to be the fair market value, then a significant portion of the capital loss carryover could expire before it is utilized.

4. Long-Term Debt

Our long-term debt as of December 31, 2002 and 2001, is as follows:

	2002	2001
Bank Borrowings	$ —	$ 134,000,000
Senior Notes due 2009	124,271,973	124,197,128
Senior Notes due 2012	200,000,000	—
Long-Term Debt	$ 324,271,973	$ 258,197,128

Bank Borrowings. At December 31, 2002, we had no outstanding borrowings under our $300.0 million credit facility with a syndicate of nine banks which has a borrowing base of $195.0 million and expires in October 2005. At December 31, 2001, we had borrowings of $134.0 million under our credit facility. The interest rate is either (a) the lead bank's prime rate (4.25% at December 31, 2002) 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. Of the $134.0 million borrowed at December 31, 2001, $130.0 million was borrowed at the LIBOR rate plus applicable margin, which averaged 3.64%.

The terms of our credit facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed $5.0 million in any fiscal year), a remaining aggregate limitation on purchases of our stock of $15.0 million, requirements as to maintenance of certain minimum financial ratios (principally pertaining to working capital, debt, and equity ratios), and limitations on incurring other debt. Since inception, no cash dividends have been declared on our common stock. We are currently in compliance with the provisions of this agreement. The credit facility is secured by our domestic oil and gas properties. We have also pledged 65% of the stock in our two active 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 in November 2002 with the same $195.0 million borrowing base. The next scheduled borrowing base review is in May 2003.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $3,618,570 in 2002, $5,833,564 in 2001, and $654,936 in 2000. The amount of commitment fees included in interest expense was $569,773, $306,663, and $284,633 in 2002, 2001, and 2000, respectively.

Convertible Notes. In November 1996, we sold $115.0 million of 6.25% Convertible Subordinated Notes due 2006. The Convertible Notes were unsecured and convertible into Swift common stock at the option of the holders at an adjusted conversion price of $31.534 per share. Interest on the notes was payable semiannually, on May 15 and November 15. On December 11, 2000, we called for the redemption of our Convertible Notes effective December 26, 2000, at 103.75% of their principal amount. Holders of approximately $100.0 million of the Convertible Notes elected to convert their notes into 3,164,644 shares of our common stock. Holders of the remaining $15.0 million of the Convertible Notes elected to redeem their notes for cash plus accrued interest. This cash redemption resulted in our recognizing an Extraordinary Loss on the Early Extinguishment of Debt (net of taxes) of $0.6 million, or $1.0 million before taxes.

Interest expense on the Convertible Notes, including amortization of debt issuance costs, totaled $7,426,599 in 2000.

Senior Notes Due 2009. Our Senior Notes due 2009 consist of $125.0 million of 10.25% Senior Subordinated Notes due August 2009. The Senior Notes were issued at 99.236% of the principal amount on August 4, 1999, and will mature on August 1, 2009. The Senior Notes are unsecured senior subordinated obligations and are subordinated in right of payment to all our existing and future senior debt, including our bank debt. Interest on the Senior Notes is payable semiannually, on February 1 and August 1, and commenced with the first payment on February 1, 2000. On or after August 1, 2004, the Senior Notes are redeemable for cash at the option of Swift, with certain restrictions, at 105.125% of principal, declining to 100% in 2007. Upon certain changes in control of Swift, each holder of Senior Notes will have the right to require us to repurchase the Senior Notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. We are currently in compliance with the provisions of the indenture governing the Senior Notes.

Interest expense on the Senior Notes due 2009, including amortization of debt issuance costs and discount, totaled $13,156,973 in 2002, $13,123,052 in 2001, and $13,092,127 in 2000.

Senior Notes Due 2012. Our Senior Notes due 2012 at December 31, 2002, consist of $200,000,000 of 9.375% Senior Subordinated Notes due May 2012. The Senior Notes 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 debt. Interest on the Senior 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, the Senior Notes are redeemable for cash at the option of Swift, with certain restrictions, at 104.688% of principal, declining to 100% in 2010. In addition, prior to May 1, 2005, we may redeem up to 33.33% of the Senior Notes with the proceeds of qualified offerings of our equity at 109.375% of the principal amount of the Senior Notes, together with accrued and unpaid interest. Upon certain changes in control of Swift, each holder of Senior Notes will have the right to require us to repurchase the Senior Notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. We are currently in compliance with the provisions of the indenture governing the Senior Notes.

Interest expense on the Senior Notes due 2012, including amortization of debt issuance costs and discount, totaled $13,525,599 in 2002.

We have capitalized interest in the amount of $7,000,000, $6,300,000, and $5,000,000 in 2002, 2001, and 2000, respectively.

5. Commitments and Contingencies

Total rental and lease expenses were $1,923,451 in 2002, $1,322,611 in 2001, and $1,255,474 in 2000. Our remaining minimum annual obligations under non-cancelable operating lease commitments are $2,190,363 for 2003, $2,191,495 for 2004, $523,755 for 2005, $190,676 for 2006, $190,676 in 2007 and $186,834 thereafter or $5,473,799 in the aggregate. The rental and lease expenses and remaining minimum annual obligations under non-cancelable operating lease commitments primarily relate to the lease of our office space in Houston, Texas, and in New Zealand.

In the ordinary course of business, we have entered into agreements with pipeline operators that require us to contribute a portion of the pipeline construction cost in the event certain transportation volumes are not met. We have $933,666 accrued in "Accounts payable and accrued liabilities" at December 31, 2002, on the accompanying balance sheet related to these commitments.

As of December 31, 2002, we were the managing general partner of six limited partnerships. Because we serve as the general partner of these entities, under state partnership law we are contingently liable for the liabilities of these partnerships, which liabilities are not material for any of the periods presented in relation to the partnerships' respective assets.

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

6. Stockholders' Equity

Common Stock. In December 2000, the holders of approximately $100.0 million of our Convertible Notes converted such notes into 3,164,644 shares of our common stock, which resulted in an increase in our common stock capital accounts of approximately $97.4 million.

During the first quarter of 2002, we issued 1.725 million shares of common stock at a price of $18.25 per share. Gross proceeds from this offering were $31,481,250, with issuance costs of $998,191.

Stock-Based Compensation Plans. We have two current stock option plans, 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. In addition, we have an employee stock purchase plan.

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 are automatically granted options to purchase shares of common stock on a formula basis. Both plans provide that the exercise prices equal 100% of the fair value of the common stock on the date of grant. Unless otherwise provided, options become exercisable for 20% of the shares on the first anniversary of the grant of the option and are exercisable for an additional 20% per year thereafter. Options granted expire 10 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 option price is credited to common stock and additional paid-in capital.

The employee stock purchase plan provides eligible employees the opportunity to acquire shares of Swift common stock at a discount through payroll deductions. The plan year is from June 1 to the following May 31. The first year of the plan commenced June 1, 1993. To date, employees have been allowed to authorize payroll deductions of up to 10% of their base salary during the plan year by making an election to participate prior to the start of a plan year. The purchase price for stock acquired under the plan is 85% of the lower of the closing price of our common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year or a date during the year chosen by the participant. Under this plan for the last three years, we have issued 9,801 shares at a price of $12.47 in 2002, 22,360 shares at a price of $21.41 in 2001, and 29,889 shares at a price range of $8.40 to $10.57 in 2000. The estimated weighted average fair value of shares issued under this plan, as determined using the Black-Scholes option-pricing model, was $1.92 in 2002, $8.19 in 2001, and $4.25 in 2000. As of December 31, 2002, 352,627 shares remained available for issuance under this plan. There are no charges or credits to income in connection with this plan.

We account for our stock option plans under Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees." As all options were issued at a price equal to market price, no compensation expense has been recognized. 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 (loss) and earnings (loss) per share would have been adjusted to the following pro forma amounts:

		2002	2001	2000
Net Income (Loss):	As Reported	$11,923,227	$(22,347,765)	$59,184,008
	Stock-based employee compensation expense determined under fair value method for all awards, net of tax	(4,451,799)	(4,284,859)	(2,652,343)
	Pro Forma	$ 7,471,428	$(26,632,624)	$56,531,665
Basic EPS:	As Reported	$0.45	$(0.90)	$2.79
	Pro Forma	$0.28	$(1.08)	$2.66
Diluted EPS:	As Reported	$0.45	$(0.90)	$2.51
	Pro Forma	$0.27	$(1.08)	$2.40

Pro forma compensation cost reflected above may not be representative of the cost to be expected in future years. The following is a summary of our stock options under these plans as of December 31, 2002, 2001, and 2000:

	2002		2001		2000	
	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price	Shares	Wtd. Avg. Exer. Price
Options outstanding, beginning of period	2,639,504	$ 17.44	2,076,593	$ 11.70	2,148,511	$ 9.08
Options granted	585,055	$ 12.32	747,073	$ 31.51	645,944	$ 16.88
Options canceled	(84,254)	$ 23.37	(31,247)	$ 14.09	(174,412)	$ 8.71
Options exercised	(121,800)	$ 8.61	(152,915)	$ 8.69	(543,450)	$ 8.48
Options outstanding, end of period	3,018,505	$ 16.64	2,639,504	$ 17.44	2,076,593	$ 11.70
Options exercisable, end of period	1,480,490	$ 13.71	1,181,141	$ 11.49	897,711	$ 9.35
Options available for future grant, end of period	419,845		1,155,057		181,235	
Estimated weighted average fair value per share of options granted during the year	$9.55		$20.68		$10.90	

The fair value of each option grant, as opposed to its exercise price, is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions in 2002, 2001, and 2000, respectively: no dividend yield; expected volatility factors of 73.72%, 46.9%, and 46.7%; risk-free interest rates of 4.74%, 5.24%, and 6.61%; and expected lives of 7.4, 7.3, and 6.7 years. The following table summarizes information about stock options outstanding at December 31, 2002:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding at 12/31/02	Wtd. Avg. Remaining Contractual Life	Wtd. Avg. Exercise Price	Number Exercisable at 12/31/02	Wtd. Avg. Exercise Price
$ 5.00 to $16.99	2,018,767	6.2	$ 10.32	1,126,267	$ 9.31
$17.00 to $28.99	272,480	5.4	$ 23.01	183,625	$ 23.52
$29.00 to $41.00	727,258	8.1	$ 31.82	170,598	$ 32.18
$ 5.00 to $41.00	3,018,505	6.6	$ 16.64	1,480,490	$ 13.71

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, and service is recognized after the ESOP effective date. 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. Compensation expense is reported when such shares are released to employees. The plan may also acquire Swift common stock, purchased at fair market value. The ESOP can borrow money from Swift to buy Swift stock. Benefits will be paid in a lump sum or installments, and the participants generally have the choice of receiving cash or stock. At December 31, 2002, 2001, and 2000, all of the ESOP compensation was earned.

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 contribution to the 401(k) savings plan totaled $603,000, $558,000, and $483,000 for the years ended December 31, 2002, 2001, and 2000, respectively. The contributions in 2002 and 2001 were made all in common stock, while the 2000 contribution was made half in common stock and half in cash. The shares of common stock contributed to the 401(k) savings plan totaled 64,490, 28,798, and 7,175 shares for the 2002, 2001, and 2000 contributions, respectively.

Common Stock Repurchase Program. 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, 2002, 610,123 shares remain in treasury (net of 317,651 shares used to fund ESOP, 401(k) contributions and acquisitions) with a total cost of $8,749,922 and are included in "Treasury stock held, at cost" on the balance sheet.

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

7. Related-Party Transactions

We are the operator of a number of properties owned by our affiliated limited partnerships and, accordingly, charge these entities operating fees. The operating fees charged to the partnerships in 2002, 2001, and 2000 totaled approximately $300,000, $925,000, and $1,775,000, respectively, and are recorded as reductions in general and administrative expense and oil and gas production expense. We are also reimbursed for direct, administrative, and overhead costs incurred in conducting the business of the limited partnerships, which totaled approximately $973,000, $3,140,000, and $4,465,000 in 2002, 2001, and 2000, respectively. In partnerships in which the limited partners have voted to sell their remaining properties and liquidate their limited partnerships, we are also reimbursed for direct, administrative, and overhead costs incurred in the disposition of such properties, which costs totaled approximately $510,000, $2,360,000, and $1,220,000 in 2002, 2001, and 2000, respectively.

8. Foreign Activities

As of December 31, 2002, our gross capitalized oil and gas property costs in New Zealand totaled approximately $172.8 million. Approximately $145.0 million have been included in the proved properties portion of our oil and gas properties while $27.8 million is included as unproved properties. Our functional currency in New Zealand is the U.S. dollar.

9. Acquisitions and Dispositions

New Zealand

Through our subsidiary, Swift Energy New Zealand Limited ("SENZ"), we acquired Southern Petroleum (NZ) Exploration Limited ("Southern NZ") in January 2002 for approximately $51.4 million in cash. We allocated $36.1 million of the acquisition price to "Proved properties," $10.0 million to "Unproved properties," $4.9 million to "Deferred income taxes" and $0.4 million to "Other current assets" on our Consolidated Balance Sheet. Southern NZ was an affiliate of Shell New Zealand and owns interests in four onshore producing oil and gas fields, hydrocarbon processing facilities, and pipelines connecting the fields and facilities to export terminals and markets. This acquisition was accounted for by the purchase method of accounting. In conjunction with this TAWN acquisition, we granted Shell New Zealand a short-term option to acquire an undivided 25% interest in our permit 38719, which included our Rimu and Kauri areas and the Rimu Production Station. This option was not exercised and expired on May 15, 2002.

In March 2002, we purchased through our subsidiary, SENZ, all of the New Zealand assets owned by Antrim for 220,000 shares of Swift Energy common stock valued at $4.2 million and an effective date adjustment of approximately $0.5 million for total consideration of $4.7 million. Antrim owned a 5% interest in permit 38719 and a 7.5% interest in permit 38716.

In September 2002, we purchased through our subsidiary, SENZ, Bligh's 5% working interest in permit 38719 and 5% interest in the Rimu petroleum mining permit 38151, along with their 3.24% working interest in the four TAWN petroleum mining licenses for 300,000 shares of Swift Energy common stock valued at $3.9 million and $2.7 million in cash for total consideration of $6.6 million.

Russia

In 1993, we entered into a Participation Agreement with Senega, a Russian Federation joint stock company, to assist in the development and production of reserves from two fields in Western Siberia and received a 5% net profits interest. We also purchased a 1% net profits interest. Our investment in Russia was fully impaired in the third quarter of 1998. In March 2002, we received $7.5 million for our investment in Russia. Although the proceeds from sales of oil and gas properties are generally treated as a reduction of oil and gas property costs, because we had previously charged to expense all $10.8 million of cumulative costs relating to our Russian activities, this cash payment, net of transaction expenses, resulted in recognition of a $7.3 million non-recurring gain on asset disposition in the first quarter of 2002.

Supplemental Information (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, 2002:			
Proved oil and gas properties	$1,150,633,802	$1,005,583,492	$ 145,050,310
Unproved oil and gas properties	69,603,481	41,850,890	27,752,591
	1,220,237,283	1,047,434,382	172,802,901
Accumulated depreciation, depletion, and amortization	(498,619,342)	(485,289,654)	(13,329,688)
Net capitalized costs	$ 721,617,941	$ 562,144,728	$ 159,473,213
December 31, 2001:			
Proved oil and gas properties	$ 974,698,428	$ 929,172,460	$ 45,525,968
Unproved oil and gas properties	95,943,163	57,096,694	38,846,469
	1,070,641,591	986,269,154	84,372,437
Accumulated depreciation, depletion, and amortization	(442,337,531)	(442,166,052)	(171,479)
Net capitalized costs	$ 628,304,060	$ 544,103,102	$ 84,200,958

Of the $41,850,890 of domestic unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2002, excluded from the amortizable base, $10,041,167 was incurred in 2002, $16,553,117 was incurred in 2001, $7,068,192 was incurred in 2000, and $8,188,414 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 $27,752,591 of net New Zealand unproved property costs at December 31, 2002, excluded from the amortizable base, $18,392,660 was incurred in 2002, $2,717,517 was incurred in 2001, $4,427,033 was incurred in 2000, and $2,215,381 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.

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

	Year Ended December 31, 2002		
	Total	Domestic	New Zealand
Acquisition of proved properties	$ 64,229,283	$ 5,415,932	$ 58,813,351
Lease acquisitions[1]	16,009,939	10,789,876	5,220,063
Exploration	18,395,335	7,571,215	10,824,120
Development	47,407,087	40,366,378	7,040,709
Total acquisition, exploration, and development[2]	$ 146,041,644	$ 64,143,401	$ 81,898,243
Processing plants	$ 7,845,520	$ 1,313,299	$ 6,532,221
Field compression facilities	2,251,247	2,251,247	—
Total plants and facilities	$ 10,096,767	$ 3,564,546	$ 6,532,221
Total costs incurred	$ 156,138,411	$ 67,707,947	$ 88,430,464

	Year Ended December 31, 2001		
	Total	Domestic	New Zealand
Acquisition of proved properties	$ 41,286,539	$ 40,491,203	$ 795,336
Lease acquisitions[1]	31,225,493	25,688,068	5,537,425
Exploration	41,981,536	35,944,405	6,037,131
Development	132,246,713	112,597,856	19,648,857
Total acquisition, exploration, and development[2]	$ 246,740,281	$ 214,721,532	$ 32,018,749
Processing plants	$ 23,331,095	$ 817,454	$ 22,513,641
Field compression facilities	319,703	319,703	—
Total plants and facilities	$ 23,650,798	$ 1,137,157	$ 22,513,641
Total costs incurred	$ 270,391,079	$ 215,858,689	$ 54,532,390

	Year Ended December 31, 2000		
	Total	Domestic	New Zealand
Acquisition of proved properties	$ 34,191,883	$ 34,191,883	$ —
Lease acquisitions[1]	20,842,103	16,315,749	4,526,354
Exploration	20,150,834	18,524,883	1,625,951
Development	104,083,409	93,931,500	10,151,909
Total acquisition, exploration, and development[2]	$ 179,268,229	$ 162,964,015	$ 16,304,214
Processing plants	$ 1,819,464	$ 755,119	$ 1,064,345
Field compression facilities	203,789	203,789	—
Total plants and facilities	$ 2,023,253	$ 958,908	$ 1,064,345
Total costs incurred	$ 181,291,482	$ 163,922,923	$ 17,368,559

[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 2002, 2001, and 2000 were $23,454,234, $22,470,263, and $16,791,834, respectively.

[2]Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $10,700,000, $11,600,000, and $10,300,000 in 2002, 2001, and 2000, respectively. In addition, total includes $7,000,000, $6,300,000, and $5,000,000 in 2002, 2001, and 2000, respectively, of capitalized interest on unproved properties.

Results of Operations. New Zealand operations began in 2001 while all our oil and gas operations in 2000 were domestic. The following table sets forth results of our oil and gas operations:

	Year Ended December 31, 2002		
	Total	Domestic	New Zealand
Oil and gas sales	$141,195,713	$112,065,003	$ 29,130,710
Oil and gas production costs	(41,497,312)	(33,088,958)	(8,408,354)
Depreciation and depletion	(55,254,467)	(42,807,364)	(12,447,103)
	44,443,934	36,168,681	8,275,253
Provision for income taxes	15,860,064	13,129,231	2,730,833
Results of producing activities	$ 28,583,870	$ 23,039,450	$ 5,544,420
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.11	$ 1.25	$ 0.80

	Year Ended December 31, 2001		
	Total	Domestic	New Zealand
Oil and gas sales	$181,184,635	$179,360,844	$ 1,823,791
Oil and gas production costs	(36,719,609)	(36,554,418)	(165,191)
Depreciation and depletion	(58,589,116)	(58,417,637)	(171,479)
Write-down of oil and gas properties	(98,862,247)	(98,862,247)	—
	(12,986,337)	(14,473,458)	1,487,121
Provision (benefit) for income taxes	(4,647,810)	(5,138,560)	490,750
Results of producing activities	$ (8,338,527)	$ (9,334,898)	$ 996,371
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.31	$ 1.32	$ 0.34

	Year Ended December 31, 2000		
	Total	Domestic	New Zealand
Oil and gas sales	$189,138,947	$189,138,947	$ —
Oil and gas production costs	(29,220,315)	(29,220,315)	—
Depreciation and depletion	(46,849,819)	(46,849,819)	—
	113,068,813	113,068,813	—
Provision for income taxes	40,365,566	40,365,566	—
Results of producing activities	$ 72,703,247	$ 72,703,247	$ —
Amortization per physical unit of production (equivalent Mcf of gas)	$ 1.11	$ 1.11	$ —

These results of operations do not include the effects of our hedging activities.

Supplemental Reserve 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's summary report dated February 7, 2003, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 2002, 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, 1999[1]	329,959,750	20,806,263	329,959,750	20,806,263	—	—
Revisions of previous estimates[2]	(4,300,787)	(455,606)	(4,300,787)	(455,606)	—	—
Purchases of minerals in place	26,567,925	2,196,547	26,567,925	2,196,547	—	—
Sales of minerals in place	(363,262)	(76,288)	(363,262)	(76,288)	—	—
Extensions, discoveries, and other additions	93,869,841	15,134,694	38,556,364	3,943,807	55,313,477	11,190,887
Production[3]	(27,119,491)	(2,472,014)	(27,119,491)	(2,472,014)	—	—
Proved reserves as of December 31, 2000	418,613,976	35,133,596	363,300,499	23,942,709	55,313,477	11,190,887
Revisions of previous estimates[2]	(122,127,541)	5,621,556	(101,693,477)	8,460,690	(20,434,064)	(2,839,134)
Purchases of minerals in place	10,038,803	7,430,591	10,038,803	7,430,591	—	—
Sales of minerals in place	(7,508,064)	(555,586)	(7,508,064)	(555,586)	—	—
Extensions, discoveries, and other additions	52,353,909	8,907,852	50,810,697	6,257,441	1,543,212	2,650,411
Production	(26,458,958)	(3,055,373)	(26,458,958)	(2,971,112)	—	(84,261)
Proved reserves as of December 31, 2001	324,912,125	53,482,636	288,489,500	42,564,733	36,422,625	10,917,903
Revisions of previous estimates[2]	(29,972,714)	5,298,439	(29,470,419)	8,675,082	(502,295)	(3,376,643)
Purchases of minerals in place	51,940,044	3,711,948	226,245	24,207	51,713,799	3,687,741
Sales of minerals in place	(3,839,124)	(464,490)	(3,839,124)	(464,490)	—	—
Extensions, discoveries, and other additions	10,822,919	12,180,558	197,919	11,304,782	10,625,000	875,776
Production	(27,131,578)	(3,770,128)	(15,780,059)	(3,074,674)	(11,351,519)	(695,454)
Proved reserves as of December 31, 2002	326,731,672	70,438,963	239,824,062	59,029,640	86,907,610	11,409,323
Proved developed reserves:						
December 31, 1999	174,046,096	8,437,299	174,046,096	8,437,299	—	—
December 31, 2000	215,169,833	10,980,196	215,169,833	10,980,196	—	—
December 31, 2001	181,651,578	23,759,574	167,401,736	20,393,142	14,249,842	3,366,432
December 31, 2002[4]	233,514,572	35,928,395	149,731,562	26,530,112	83,783,010	9,398,283

[1]Proved reserves exclude quantities subject to our volumetric production payment agreement, which expired with the last required delivery of volumes in October 2000.

[2]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 and natural gas prices at each year-end. Proved reserves, as of December 31, 2002, were based upon prices in effect at year-end. The weighted average of 2002 year-end prices for total, domestic, and New Zealand were \$3.49, \$4.23, and \$1.48 per Mcf of natural gas, \$29.27, \$29.36, and \$28.80 per barrel of oil and \$16.54, \$17.30 and \$12.24 per barrel of NGL, respectively. This compares to \$2.51, \$2.68, and \$1.18 per Mcf, \$18.45, \$18.51, and \$18.25 per barrel of oil and \$10.70, \$11.00 and \$8.90 per barrel of NGL as of December 31, 2001, for total, domestic, and New Zealand, respectively.

[3]Natural gas production for 2000 excludes 405,130 Mcf, respectively, delivered under our volumetric production payment agreement.

[4]*At December 31, 2002, 60% of our reserves are proved developed and 40% are proved undeveloped.*

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, 2002		
	Total	Domestic	New Zealand
Future gross revenues	$ 2,990,669,570	$ 2,578,435,576	$ 412,233,994
Future production costs	(720,599,745)	(612,094,088)	(108,505,657)
Future development costs	(224,792,520)	(208,492,520)	(16,300,000)
Future net cash flows before income taxes	2,045,277,305	1,757,848,968	287,428,337
Future income taxes	(599,195,484)	(512,966,321)	(86,229,163)
Future net cash flows after income taxes	1,446,081,821	1,244,882,647	201,199,174
Discount at 10% per annum	(609,212,030)	(540,375,347)	(68,836,683)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 836,869,791	$ 704,507,300	$ 132,362,491

	Year Ended December 31, 2001		
	Total	Domestic	New Zealand
Future gross revenues	$ 1,706,475,138	$ 1,485,480,927	$ 220,994,211
Future production costs	(483,588,857)	(436,141,429)	(47,447,428)
Future development costs	(198,172,628)	(185,347,628)	(12,825,000)
Future net cash flows before income taxes	1,024,713,653	863,991,870	160,721,783
Future income taxes	(261,635,331)	(208,726,729)	(52,908,602)
Future net cash flows after income taxes	763,078,322	655,265,141	107,813,181
Discount at 10% per annum	(308,520,417)	(274,882,174)	(33,638,243)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 454,557,905	$ 380,382,967	$ 74,174,938

	Year Ended December 31, 2000		
	Total	Domestic	New Zealand
Future gross revenues	$ 4,995,951,799	$ 4,737,560,630	$ 258,391,169
Future production costs	(817,127,348)	(807,436,139)	(9,691,209)
Future development costs	(204,620,116)	(180,320,116)	(24,300,000)
Future net cash flows before income taxes	3,974,204,335	3,749,804,375	224,399,960
Future income taxes	(1,321,061,952)	(1,243,731,594)	(77,330,358)
Future net cash flows after income taxes	2,653,142,383	2,506,072,781	147,069,602
Discount at 10% per annum	(1,075,183,917)	(1,017,995,158)	(57,188,759)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 1,577,958,466	$ 1,488,077,623	$ 89,880,843

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 certain abandonment 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 and do not include the effects of our hedging activities. 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 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 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,		
	2002	2001	2000
Beginning balance	$ 454,557,905	$1,577,958,466	$ 438,943,834
Revisions to reserves proved in prior years—			
Net changes in prices, production costs, and future development costs	373,890,614	(1,692,627,074)	1,523,487,598
Net changes due to revisions in quantity estimates	2,582,633	(93,669,181)	(36,102,814)
Accretion of discount	60,298,619	231,325,481	56,405,451
Other	(88,675,455)	(204,768,815)	(220,119,873)
Total revisions	348,096,411	(1,759,739,589)	1,323,670,362
New field discoveries and extensions, net of future production and development costs	190,461,371	110,213,160	359,265,150
Purchases of minerals in place	76,538,437	39,544,163	160,240,785
Sales of minerals in place	(5,769,642)	(50,131,970)	(598,021)
Sales of oil and gas produced, net of production costs	(99,698,403)	(144,262,145)	(159,331,003)
Previously estimated development costs incurred	48,752,814	94,107,760	65,953,028
Net change in income taxes	(176,069,102)	586,868,060	(610,185,669)
Net change in standardized measure of discounted future net cash flows	382,311,886	(1,123,400,561)	1,139,014,632
Ending balance	$ 836,869,791	$ 454,557,905	$1,577,958,466

Quarterly Data (Unaudited). The following table presents summarized quarterly financial information for the years ended December 31, 2001 and 2002:

	Revenues	Income/(Loss) Before Income Taxes, Extra-ordinary Item and Change in Accounting Principle[b]	Income/(Loss) Before Extra-ordinary Item and Change in Accounting Principle[b]	Net Income/(Loss)	Basic EPS Income/(Loss) Before Extra-ordinary Item and Change in Accounting Principle[b]	Diluted EPS Income/(Loss) Before Extra-ordinary Item and Change in Accounting Principle[b]	Basic EPS Net Income/(Loss)	Diluted EPS Net Income/(Loss)
2001:								
First Quarter	$ 62,392,014	$ 35,513,130	$ 22,719,653	$ 22,326,785	$ 0.92	$ 0.89	$ 0.91	$ 0.88
Second Quarter	52,303,265	23,408,900	14,972,946	14,972,946	0.61	0.59	0.61	0.59
Third Quarter	41,244,583	11,607,563	7,420,090	7,420,090	0.30	0.29	0.30	0.29
Fourth Quarter	27,867,628	(104,721,926)	(67,067,586)	(67,067,586)	(2.71)	(2.71)	(2.71)	(2.71)
Total	$183,807,490	$ (34,192,333)	$ (21,954,897)	$ (22,347,765)	$ (0.89)	$ (0.89)	$ (0.90)	$ (0.90)
2002:								
First Quarter[a]	$ 34,354,077	$ 4,674,075	$ 3,019,810	$ 3,019,810	$ 0.12	$ 0.12	$ 0.12	$ 0.12
Second Quarter	38,570,269	5,518,886	3,584,092	3,584,092	0.13	0.13	0.13	0.13
Third Quarter	36,570,809	2,933,350	1,947,006	1,947,006	0.07	0.07	0.07	0.07
Fourth Quarter	40,474,656	5,281,978	3,372,319	3,372,319	0.12	0.12	0.12	0.12
Total	$149,969,811	$ 18,408,289	$ 11,923,227	$ 11,923,227	$ 0.45	$ 0.45	$ 0.45	$ 0.45

[a]First quarter 2002 results include a gain on asset disposition of $7,332,668.

[b]There were no extraordinary items in 2001 or 2002.

Form 10-K Excerpts

PART I

Items 1 and 2. Business and Properties

See pages 63 and 64 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 onshore and inland waters oil and natural gas reserves in Texas and Louisiana and onshore oil and natural gas reserves in New Zealand. The Company was founded in 1979 and is headquartered in Houston, Texas. As of December 31, 2002, we had interests in 932 wells located domestically in three states, in federal offshore waters, and in New Zealand. We operated 820 of these wells representing 95% our proved reserves. At year-end 2002, we had estimated proved reserves of 749.4 Bcfe, of which approximately 44% was natural gas, 42% crude oil, and 14% NGLs, and overall 60% was proved developed. Our proved reserves are concentrated 41% in Texas, 35% in Louisiana, and 21% in New Zealand.

We currently focus primarily on development and exploration in four domestic core areas and two core areas in New Zealand:

Area	Location	% of Year-End 2002 Proved Reserves	% of 2002 Production
AWP Olmos	South Texas	30%	22%
Brookeland	East Texas	6%	8%
Lake Washington	South Louisiana	25%	9%
Masters Creek	Central Louisiana	10%	20%
Rimu/Kauri	New Zealand	12%	3%
TAWN	New Zealand	9%	28%
% of Total		92%	90%

We have a well-balanced portfolio of oil and gas properties and prospects. The AWP Olmos and Lake Washington areas and New Zealand are characterized by long-lived reserves that we expect to be steadily produced over a long period of time. The Masters Creek and Brookeland areas are characterized by shorter-lived reserves with high initial rates of production that decline rapidly. We believe these shorter-lived reserves complement our long-lived reserves. We focus on drilling the long-lived properties during periods of decreasing commodity prices, while the shorter-lived properties provide additional drillable projects in periods of rising commodity prices. Based on 2002 year-end proved reserves and 2002 production, we calculated our average reserve life as 17.4 years domestically and 10.0 years in New Zealand.

We have increased our proved reserves from 361.5 Bcfe at year-end 1997 to 749.4 Bcfe at year-end 2002, which has resulted in the replacement of 278% of our production during the same five-year period. Our five-year average reserves replacement costs were $1.25 per Mcfe. Our average annual reserve replacement costs for the last five years, starting with 2002 were $0.96, $3.30, $0.81, $1.27 and $1.20 per Mcfe. In 2002, we increased our proved reserves by 16%, which replaced 308% of our 2002 production. Our 2002 production increased by 11% in relation to 2001 production. We have increased our production from 25.4 Bcfe at year-end 1997 to 49.8 Bcfe at year-end 2002. Primarily due to increased production, this has resulted in average annual growth in net cash provided by operating activities of 5% per year from year-end 1997 to year-end 2002, even though in 2002 net cash provided by operating activities fell 49% due to pricing changes.

Through intensive efforts, we have developed an inventory of exploration and development prospects, identifying drilling locations through integrated geological and geophysical studies of our undeveloped acreage and other prospects. As a result, we added 184.7 Bcfe of proved reserves through drilling in 2000 (122.5 Bcfe from New Zealand), 105.8 Bcfe in 2001 (17.4 Bcfe from New Zealand), and 83.9 Bcfe in 2002 (15.9 Bcfe from New Zealand). The 2002 additions were primarily a result of our development success rate, as 17 of 23 domestic development wells drilled were successful, while three of seven domestic exploratory wells were successful.

We purchased interests in the Brookeland and Masters Creek areas from Sonat Exploration Company in the third quarter of 1998 for approximately $85.8 million in cash. In the first quarter of 2001, we purchased interests in the Lake Washington field from Elysium Energy, LLC, for approximately $30.5 million in cash. In the first quarter of 2002, we purchased interests in the four TAWN fields in New Zealand for approximately $51.4 million, which also included significant infrastructure, after purchase price adjustments.

We currently plan to spend $115 to $130 million in total capital expenditures in 2003, excluding acquisition costs and net of approximately $5 million to $15 million in non-core property dispositions. The budget for 2003 is largely dependent upon our performance and commodity pricing during the year. Domestic activities account for 85% of our budgeted spending, primarily in the Lake Washington Area.

Competitive Strengths and Business Strategy

We believe that our competitive strengths, together with a balanced and comprehensive business strategy, provide us with the flexibility and capability to accomplish our goals.

Balanced Approach to Adding Reserves

When we believe the market favors increasing reserves through acquisitions, we apply our considerable experience in evaluating and negotiating prospective acquisitions. For example, in 1998, when commodity prices were relatively weak, 32% of our capital expenditures consisted of property acquisitions, with 37% committed to our drilling activities. In contrast, in 2001, when commodity prices were relatively strong in the first half of the year, only 15% of our capital expenditures were spent on property acquisitions, with our drilling expenditures increasing to 67% of total capital expended. We believe this balanced approach has resulted in our ability to grow reserves in a relatively low cost manner, while participating in the upside potential of exploration.

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. Generally, we seek to acquire properties with the potential for additional reserves and production through development and exploration efforts.

In addition, we seek to enhance the results of our drilling and production efforts through the implementation of advanced technologies.

During 2002, in response to strong oil prices throughout the year, we focused our capital expenditures on the Lake Washington Area domestically and on the TAWN acquisition in New Zealand. Although oil prices remained strong in 2002, natural gas prices for most of the year were lower than prior year levels, and our cash flow generated due to these commodity prices decreased, as expected, even though production increased. As a result of lower cash flow in 2002, we reduced our capital expenditures to $155.2 million. Of this amount, $58.4 million was spent on acquisitions, mainly the TAWN acquisition in New Zealand. We spent $42.7 million on drilling in the United States, with $34.4 for development drilling and $8.3 million for exploratory drilling. In New Zealand we spent $22.9 million on drilling, with $12.6 million for development drilling and $10.3 million for exploratory drilling. We also spent $10.6 million constructing a gas processing plant in New Zealand. The remaining capital expenditures of $20.6 million were spent primarily on leasehold, seismic, and geological costs of prospects, both in the United States and New Zealand. During 2002, we principally relied upon cash flows from operations of $71.6 million, net proceeds from the issuance of long-term debt of $195.0 million, and net proceeds from our public stock offering of $30.5 million, less the repayment of bank borrowings of $134.0 million, to fund our capital expenditures.

In 145 transactions from 1979 to 2002, we have acquired approximately $695.7 million of producing oil and gas properties on behalf of our co-investors and ourselves. We acquired, for our own account, approximately $339.2 million of producing properties, with original proved reserves estimated at 468.5 Bcfe during this period. Our producing property acquisition expenditures in the past three years were $64.2 million in 2002, $41.3 million in 2001, and $34.2 million in 2000. Our acquisition costs have averaged $0.83 per Mcfe over this three-year period. Our acquisition cost in 2002 averaged $0.87 per Mcfe.

Concentrated Focus on Core Areas

Our concentration of reserves and our significant acreage positions in our core areas allow us to realize economies of scale in drilling and production. We enhance the value of this concentration by acting as the operator of 95% of our proved reserves at year-end 2002. Our operational control allows us to better manage production, control our expenses, allocate capital and time field development. We intend to continue to acquire large acreage positions in under-explored and under-exploited areas, where, as operator, we can exploit successful discoveries to create new core areas or grow production from developed fields. In executing this strategy:

• We focus our resources on acquiring properties that we can operate, and in which we can obtain a significant working interest. With operational control, we can apply our technical and operational expertise to optimize our exploration and exploitation of the properties that we acquire.

• We acquire and operate domestic properties in a limited number of geographic areas. Operating in a concentrated area helps us to better control our overhead by enabling us to manage a greater amount of acreage with fewer employees, minimizing incremental costs of increased drilling and production.

• We continue to believe in natural gas prospects and reserves in the United States. The natural gas market in the United States has a well-developed infrastructure. Natural gas is viewed by many as the preferred fuel in North America for several reasons, including environmental concerns. We have a strong inventory of natural gas that can be developed in a higher priced environment.

• We seek to operate large acreage positions with high exploration and development potential. For example, on our original 100,000 acre New Zealand permit, only two wells had been drilled at the time that we acquired our interest. The Masters Creek, Brookeland and Lake Washington areas also had significant additional development potential when we first acquired our interest in those areas.

Ability to Build Upon our Recent Discoveries and Acquisitions in New Zealand

Our New Zealand activities provide us with long-term growth opportunities and significant potential reserves in a country with stable political and economic conditions, existing oil and gas infrastructure, and favorable tax and royalty regimes. We have completed construction of our Rimu production and gas processing facilities, which became operational in May 2002 and enabled us to begin the sale of production from the Rimu/Kauri area. We were able to bring our Rimu discovery on commercial production in a significantly shorter period than any other similar project previously undertaken in New Zealand of which we are aware.

In January 2002, we acquired the TAWN fields. In our TAWN acquisition, we also acquired extensive associated processing facilities and pipelines, which give us a competitive advantage through infrastructure that complements our existing fields, providing us with increased access to export terminals and markets and additional excess processing capacity for both oil and natural gas.

Experienced Technical Team

We employ oil and gas professionals, including geophysicists, petrophysicists, geologists, petroleum engineers, and production and reservoir engineers, who have an average of approximately 25 years of experience in their technical fields and have been employed by Swift for an average of over 10 years. We continually apply our extensive in-house expertise and current advanced technologies to benefit our drilling and production operations. We have developed a particular expertise in drilling horizontal wells at vertical depths below 10,000 feet, often in a high-pressure environment, involving single or dual lateral legs of several thousand feet. This results in an integrated approach to exploration using multidisciplinary data analysis and interpretation that has helped us identify a number of exploration prospects.

We use various recovery techniques, including water flooding and acid treatments, fracturing reservoir rock through the injection of high-pressure fluid, gravel packing, and inserting coiled tubing velocity strings to enhance and maintain gas flow. We believe that the application of fracturing technology and coiled tubing has resulted in significant increases in production and decreases in completion and operating costs, particularly in our AWP Olmos Area.

We have increasingly used seismic technology to enhance the results of our drilling and production efforts, including 2-D and 3-D seismic analysis, amplitude versus offset studies, and detailed formation depletion studies.

As a result, we have maintained internal seismic expertise and have compiled an extensive database.

When appropriate, we develop new applications for existing technology. For example, in New Zealand we acquired seismic data by effectively combining marine data with the acquisition of land seismic data, an application we have not seen any other company use in New Zealand.

Financial Discipline

We practice a disciplined approach to financial management and have historically maintained a strong capital structure that preserves our ability to execute our business plan. Key components of our financial discipline include maintaining a capital budget balanced between drilling and acquisitions, establishing leverage targets that are reasonable given the volatility of the oil and gas markets, and opportunistically accessing the capital markets. As of December 31, 2002, our long-term debt comprised approximately 47% of our total capitalization. We applied the net proceeds from our common stock offering and debt offering in April 2002 in the amount of $225.5 million to reduce amounts outstanding under our credit facility. At December 31, 2002, we had $194.2 million of available borrowing capacity. By replacing indebtedness incurred under our revolving credit facility in connection with acquisition, development, and exploitation activity with the net proceeds from our common stock offering and debt offering, we implemented our strategy of matching long-lived assets with long-term financing.

Domestic Core Operating Areas

AWP Olmos Area. As of December 31, 2002, we owned approximately 27,900 net acres in the AWP Olmos Area in South Texas. We have extensive expertise and a long history of experience with low-permeability, tight-sand formations typical of this area, having acquired our first acreage there in 1988. These reserves are approximately 66% gas. At year-end 2002, we owned interests in 495 wells and operated 494 wells in this area producing gas from the Olmos sand formation at depths of approximately 9,000 to 11,500 feet. We own nearly 100% of the working interests in all our operated wells.

In 2002, we performed four fracture extensions and installed coiled tubing velocity strings in five wells. At year-end 2002, we had 128 proved undeveloped locations. Also in 2002, we purchased interests in the AWP Olmos area from partnerships we managed. Our planned 2003 capital expenditures in this area will focus on drilling 10 wells and performing fracture extensions and installing coiled tubing velocity strings to maintain a flat production profile.

Brookeland Area. As of December 31, 2002, we owned drilling and production rights in 76,259 net acres and 3,500 fee mineral acres in this area, which contains substantial proved undeveloped reserves. This area was part of the acquisition from Sonat in 1998 and is located in East Texas near the border of Louisiana in Jasper and Newton counties. It primarily contains horizontal wells producing from the Austin Chalk formation. The reserves are approximately 55% oil and natural gas liquids. At year-end 2002, we had 13 proved undeveloped locations in this area. Our planned 2003 capital expenditures in this area include drilling one development well.

Lake Washington Field. As of December 31, 2002, we owned drilling and production rights in 11,080 net acres in the Lake Washington Field. This area is located in Plaquemines Parish in South Louisiana. The reserves are approximately 98% oil and natural gas liquids. We acquired interests in the Lake Washington Field in March 2001. This field produces oil from multiple Miocene sands ranging in depth from less than 1,700 feet to greater than 9,000 feet. The field is located on a salt dome and has produced over 300 million BOE since its inception in the 1930s. The area around the dome is heavily faulted, thereby creating a large number of potential traps. Oil and gas from approximately 38 producing wells is gathered from three platforms located in water depths from 6 to 11 feet, with drilling and workover operations performed with barge rigs. In 2002, 23 development wells and four exploratory wells were drilled in the area; 17 development and two exploratory wells were successful. At year-end 2002, we had 63 proved undeveloped locations in this field. Our planned 2003 capital expenditures in this area include drilling 50 to 60 development wells and one saltwater disposal well.

Masters Creek Area. As of December 31, 2002, we owned drilling and production rights in 77,475 net acres and 107,000 fee mineral acres in this area, which contains substantial proved undeveloped reserves. This area was also part of the acquisition from Sonat in 1998. It 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 72% oil and natural gas liquids. At year-end 2002, we had 12 proved undeveloped locations in the area. Our planned 2003 capital expenditures in this area include drilling one development well.

Domestic Emerging Growth Areas

The Frio Trend. We have been focusing on the deep sands of the Frio formation (10,000 to 16,000 feet) in an area that straddles the border of Kenedy County and Willacy County in the southern tip of Texas and is identified as Garcia Ranch. Retaining a 65% working interest, we had two discoveries in the area in 2001, one in the Rome prospect in Willacy County and the other in the Siena prospect in Kenedy County. In 2002, we participated in a successful non-operated well with a 33% working interest in the Milan prospect in Kenedy county. We plan to participate in drilling two development wells in 2003 in this area.

The Wilcox Sands. We had three discoveries in the Wilcox sands during 2001, two of which were located in Goliad County, Texas: the Nita prospect drilled to a depth of approximately 15,000 feet and the Brandon prospect drilled to a depth of about 13,000 feet. Our working interests in the two wells are 73% and 60%, respectively. The third well, in which we have a 25% working interest, was in the Falcon Ridge prospect in Zapata County, Texas. We plan to participate in one development well in this area in 2003.

The Woodbine Formation. The Woodbine formation is located in southeast Texas in San Jacinto, Polk, and Tyler counties. We drilled one well to the Woodbine formation in 2001, in the Lion prospect in San Jacinto County, Texas, to a depth of 15,000 feet. Although hydrocarbon-bearing intervals were found, the well was deemed noncommercial. The Company has two other Woodbine prospects, the Jaguar and Bobcat prospects, both located in Polk County.

The Miocene Sands. We successfully drilled our first exploratory well in the Miocene sands in our Lake

Washington Area in Plaquemines Parish, Louisiana, to a depth of 3,348 feet with a retained interest of 100%. This area has substantial exploration and development potential, with sands extending from shallow depths down to 10,000 feet or more. Through 2002, we have drilled 28 wells in this area.

New Zealand Core Operating Areas

Our activity in New Zealand began in 1995. As of December 31, 2002, our permit 38719, which we operate, included approximately 49,800 acres in the Taranaki Basin of New Zealand's north island. This acreage includes our Rimu and Kauri areas as well as our Tawa and Matai prospects.

We expanded our operation in New Zealand in January 2002 with our TAWN purchase of Southern Petroleum (NZ) Exploration, Limited, from Shell New Zealand, through which we acquired interests in four fields and significant infrastructure assets.

In March 2002, we completed the acquisition of all of the New Zealand assets of Antrim. These assets included a 5% working interest in the Swift-operated permit 38719, increasing the Company's interest in this permit to 95%. An additional 7.5% interest was also acquired in permit 38716 (Huinga prospect), increasing the Company's interest to 15%.

In August 2002, we were awarded two additional onshore permits, permits 38756 and 38759. These permits include approximately 8,100 and 20,400 gross acres, respectively, in proximity to our permit 38719.

In September 2002, we completed the acquisition of Bligh's 5% working interest in permit 38719 and 5% interest in the Rimu petroleum mining permit 38151, along with their 3.24% working interest in the four TAWN petroleum mining licenses. The Company's interests in permit 38719, petroleum mining permit 38151, and the TAWN petroleum mining licenses are now 100%.

In December 2002, we agreed to acquire an additional 50% interest in permit 38718 (Tuihu prospect) from Shell New Zealand through an existing pre-emptive right under the joint operating agreement. Following the transaction, SENZ will sell a 20% interest in the permit to a subsidiary of New Zealand Oil and Gas Limited. The purchase and subsequent sale, which are subject to certain government notifications, approvals and consents, will result in SENZ holding a 50% working interest in this permit. We were named operator of the permit. Permit 38718 contains the Tuihu #1 exploratory well, which was drilled in 2001 and temporarily abandoned. Our 2003 budget calls for a re-entry of this well, which will sidetrack or deepen the original well.

As of December 31, 2002, our gross investment in New Zealand totaled approximately $172.8 million. Approximately $145.0 million of our investment costs have been included in the proved properties portion of our oil and gas properties, while $27.8 million is included as unproved properties.

Rimu Area. Early in 2002, we were awarded petroleum mining permit 38151 by the New Zealand Ministry for Economic Development for the development of the Rimu discovery over an approximately 5,500 acre area for a primary term of 30 years. Commercial production from the Rimu area began in May 2002.

During the first quarter of 2002, the Rimu-A2 sidetrack was completed and recently underwent fracture stimulation, which was unsuccessful. We plan a CO_2 stimulation project during the first half of 2003 to improve its productibility. The Rimu-B3 development well was also sidetracked in early 2002 but was unsuccessful.

Kauri Area. During 2002, three wells were drilled in the Kauri area. The Kauri-A1 exploratory well was drilled to the Upper Tariki sand, the Kauri-A3 development well was drilled to the shallow Manutahi sands, and the Kauri-A4 exploratory well was drilled through the Kauri sands and on down to the Lower Tariki sand, which was found to be too wet for commercial production. After the drilling of the Kauri-A4 well was completed in October 2002, pipe was set in the well and perforated over approximately 33 feet of the Kauri sands in preparation for a hydraulic fracture stimulation in early 2003.

TAWN Area. The TAWN acquisition in January 2002 consisted of a 96.76% working interest in four petroleum mining licenses, or PML, covering producing oil and gas fields, and extensive associated hydrocarbon-processing facilities and pipelines, which give us a competitive advantage through infrastructure that complements our existing fields, providing us with increased access to export terminals and markets and additional excess processing capacity for both oil and natural gas. The TAWN assets are located approximately 17 miles north of the Rimu area.

The properties are collectively identified as the TAWN properties, an acronym derived from the first letters of the field names – the Tariki Field (PML 38138), the Ahuroa Field (PML 38139), the Waihapa Field (PML 38140), and the Ngaere Field (PML 38141). The four fields include 17 wells where the purchaser of gas, Contact Energy, has contracted to take minimum quantities and can call for higher production levels to meet electrical demand in New Zealand. Sales gas deliveries to Contact have exceeded the contract minimum during all of 2002.

Solution gas gathered from the Waihapa Production Station ("WPS") flows to the Tariki Ahuroa gas plant ("TAG"). The current processing capacity of the WPS facility is up to 15,000 barrels of oil and 40 MMcf of natural gas per day. Processing capacity tests conducted following facility modifications completed in the third quarter have confirmed a 12% increase in the gas processing capacity of the TAG plant. A 32-mile, 8-inch diameter oil export line runs from the WPS to the Omata Tank Farm at New Plymouth, where oil export facilities allow for sales into international markets. An additional 32-mile, 8-inch diameter natural gas pipeline runs from the WPS to the Taranaki Combined Cycle Electric Generation Facility near Stratford and on to the New Plymouth Power Station.

We have a service agreement with the owner of the Omata Tank Farm to utilize the blending, storage, and export capabilities of the facility. The operator of the facility provides services for a fixed fee per barrel received and other variable costs as required by the agreement. Under the terms of the agreement, crude oil produced from the TAWN and Rimu/Kauri areas have access to the Omata Tank Farm.

Our current contract with Shell Petroleum Mining (SPM), which purchases all of our New Zealand crude oil production, runs through the end of 2003. The delivery point for our crude oil sales is the ship's flange. SPM and the Omata Tank Farm coordinate logistical issues for shipments, and thus SPM's decisions regarding sales from the Omata Tank Farm can affect the timing of sales of that portion of our production.

Rimu Production Station. We completed construction on the Rimu Production Station ("RPS") during the first quarter of 2002, and production was processed through this facility beginning in the second quarter of 2002. Our oil production processed through the RPS is transported the 17 miles by truck to our WPS facility and then sent by pipeline to the Omata Tank Farm. Our natural gas production processed through the RPS is sold to Genesis Power Ltd. under a long-term contract. Natural gas prices are substantially lower in New Zealand, as compared to domestic prices, largely due to the fact that the natural gas market has been dominated by one large field, the Maui Field, which supplies approximately 70% of the natural gas supply but is due to be depleted by 2007.

New Zealand Emerging Growth Areas

The Tawa prospect is located northwest of the Rimu and Kauri areas in the same permit. Its main targets are the Kapuni sands, the Kauri sandstones, and the Tariki sandstone. Consisting of a combination of structural and stratigraphic traps, this prospect was developed based upon Swift's analysis of existing three-dimensional seismic data plus two-dimensional seismic data acquired during Company surveys in 1997 and 2000.

The Matai prospect, located on the southeast flank of the Tawa prospect also in permit 37819, will target the Moki and Urenui sandstones. It was identified based upon the analysis of the two-dimensional seismic data Swift acquired in 2000.

The Tuihu prospect, permit 38718, is located northeast of our TAWN Area. In December 2002, we agreed to acquire an additional 50% interest in permit 38718 from Shell New Zealand though an existing pre-emptive right under the joint operating agreement. Following the transaction, SENZ will sell a 20% interest in the permit to a subsidiary of New Zealand Oil and Gas Limited. The purchase and subsequent sale, which are subject to certain government notifications, approvals and consents, will result in SENZ holding a 50% working interest in this permit. We were named operator of the permit. Permit 38718 contains the Tuihu #1 exploratory well, which was drilled in 2001 and was temporarily abandoned. Our 2003 budget calls for a re-entry of this well, which will sidetrack or deepen the original well.

The Huinga prospect, permit 38716, is located northeast of our Rimu/Kauri areas. An exploratory well was drilled on this permit, of which we own 15%, in 1998 and was temporarily abandoned. This well was re-entered in 2002 and was unsuccessful. The operator is currently re-evaluating this prospect.

Oil and Gas Reserves

The following table presents information regarding proved reserves of oil and gas attributable to our interests in producing properties as of December 31, 2002, 2001, and 2000. The information set forth in the table 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's audit was based upon review of production histories and other geological, economic, ownership, and engineering data provided by Swift.

In accordance with Securities and Exchange Commission guidelines, estimates of future net revenues from our proved reserves and the PV-10 Value must be made using oil and gas sales prices in effect as of the dates of such estimates and are held constant 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. Proved reserves as of December 31, 2002, were estimated based upon prices in effect at year-end. The weighted averages of such year-end prices domestically were $4.23 per Mcf of natural gas, $29.36 per barrel of oil, and $17.30 per barrel of NGL, compared to $2.68, $18.51, and $11.00 at year-end 2001 and $11.25, $25.50, and $20.30 at year-end 2000, respectively. The weighted averages of such year-end 2002 prices for New Zealand were $1.48 per Mcf of natural gas, $28.80 per barrel of oil, and $12.24 per barrel of NGL, compared to $1.18, $18.25, and $8.90 in 2001, respectively. The weighted averages of such year-end 2002 prices for all our reserves, both domestically and in New Zealand, were $3.49 per Mcf of natural gas, $29.27 per barrel of oil, and $16.54 per barrel of NGL, compared to $2.51, $18.45, and $10.70 in 2001, respectively. 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 table.

The table sets 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. Operating costs, development 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.

Estimated Proved Oil and Gas Reserves	Year Ended December 31, 2002 Total	Domestic	New Zealand
Net natural gas reserves (Mcf):			
Proved developed	233,514,572	149,731,562	83,783,010
Proved undeveloped	93,217,100	90,092,500	3,124,600
Total	326,731,672	239,824,062	86,907,610
Net oil and NGL reserves (Bbl):			
Proved developed	35,928,395	26,530,112	9,398,283
Proved undeveloped	34,510,568	32,499,528	2,011,040
Total	70,438,963	59,029,640	11,409,323
Estimated Present Value of Proved Reserves			
Estimated present value of future net cash flows from proved reserves discounted at 10% per annum:			
Proved developed	$ 679,356,172	$ 516,832,848	$ 162,523,324
Proved undeveloped	481,833,151	456,632,145	25,201,006
Total	$ 1,161,189,323	$ 973,464,993	$ 187,724,330

Estimated Proved Oil and Gas Reserves	Year Ended December 31, 2001 Total	Domestic	New Zealand
Net natural gas reserves (Mcf):			
Proved developed	181,651,578	167,401,736	14,249,842
Proved undeveloped	143,260,547	121,087,764	22,172,783
Total	324,912,125	288,489,500	36,422,625
Net oil and NGL reserves (Bbl):			
Proved developed	23,759,574	20,393,142	3,366,432
Proved undeveloped	29,723,062	22,171,591	7,551,471
Total	53,482,636	42,564,733	10,917,903
Estimated Present Value of Proved Reserves			
Estimated present value of future net cash flows from proved reserves discounted at 10% per annum:			
Proved developed	$ 344,478,834	$ 306,095,381	$ 38,383,453
Proved undeveloped	258,507,354	186,012,413	72,494,941
Total	$ 602,986,188	$ 492,107,794	$ 110,878,394

Estimated Proved Oil and Gas Reserves	Year Ended December 31, 2000 Total	Domestic	New Zealand
Net natural gas reserves (Mcf):			
Proved developed	215,169,833	215,169,833	—
Proved undeveloped	203,444,143	148,130,666	55,313,477
Total	418,613,976	363,300,499	55,313,477
Net oil and NGL reserves (Bbl):			
Proved developed	10,980,196	10,980,196	—
Proved undeveloped	24,153,400	12,962,513	11,190,887
Total	35,133,596	23,942,709	11,190,887
Estimated Present Value of Proved Reserves			
Estimated present value of future net cash flows from proved reserves discounted at 10% per annum:			
Proved developed	$ 1,257,570,764	$ 1,257,570,764	$ —
Proved undeveloped	1,055,684,045	919,388,009	136,296,036
Total	$ 2,313,254,809	$ 2,176,958,773	$ 136,296,036

At year-end 2002, 60% of the proved reserves were developed reserves. At year-end 2001, 50% of proved reserves were developed. At year-end 2000, 45% of proved reserves were developed.

Changes in quantity estimates and the estimated present value of proved reserves are affected by the change in crude oil and natural gas prices at the end of each year. Our total proved reserves quantities at year-end 2002 increased by 16% over reserves quantities a year earlier, while the PV-10 Value of those reserves increased 93% from the PV-10 Value at year-end 2001. While our total proved reserves quantities, on an equivalent Bcfe basis, at year-end 2001 increased by 3% over reserves quantities in 2000, the PV-10 Value of those reserves decreased 74% from the PV-10 Value at year-end 2000. This decrease in 2001 prices resulted in 47.1 Bcfe of downward reserves revision, solely attributed to the decrease in prices used in 2001. The PV-10 Value increase in 2002 and the PV-10 decrease in 2001 were heavily influenced by pricing increases at year-end 2002 as compared to year-end 2001 and by pricing decreases from year-end 2001 as compared to year-end 2000. Product prices for natural gas increased 39% during 2002, from $2.51 per Mcf at year-end 2001 to $3.49 at year-end 2002, while oil prices increased 59% between the two dates, from $18.45 to $29.27 per barrel. Product prices for natural gas decreased 75% during 2001, from $9.86 per Mcf at December 31, 2000, to $2.51 per Mcf at year-end 2001, while oil prices decreased 25% between the two dates, from $24.62 to $18.45 per barrel. Product prices for natural gas increased 282% during 2000, from $2.58 per Mcf at December 31, 1999, to $9.86 per Mcf at year-end 2000, matched by a 4% increase in the price of oil between the two dates, from $23.69 to $24.62 per barrel.

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 filed with any federal agency.

Oil and Gas Wells

As we continued to liquidate partnerships for those partnerships which voted to do so, our total gross well count decreased. Acquisitions such as Lake Washington, where we own nearly a 100% interest in all operated wells, have increased well ownership on a net basis. 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, 2002			
Gross	342	555	897
Net	278.9	479.8	758.7
December 31, 2001			
Gross	396	786	1,182
Net	297.0	467.9	764.9
December 31, 2000			
Gross	599	904	1,503
Net	165.2	484.7	649.9

[1]Excludes 35 service wells in 2002, 48 service wells in 2001, and 25 service wells in 2000. Also excludes five wells in 2001 and three wells in 2000 in New Zealand that were temporarily shut-in awaiting the commissioning of the Rimu Production Station.

Oil and Gas Acreage

As is customary in the industry, we generally acquire oil and gas acreage without any warranty of title except as to claims made by, through, or under the transferor. Although we have title to developed acreage examined prior to acquisition in those cases in which the economic significance of the acreage justifies the cost, there can be no assurance that losses will not result from title defects or from defects in the assignment of leasehold rights. In many instances, title opinions may not be obtained if in our judgment it would be uneconomical or impractical to do so.

The following table sets forth the developed and undeveloped leasehold acreage held by us at December 31, 2002:

	Developed[1]		Undeveloped[1]	
	Gross	Net	Gross	Net
Alabama	9,686.01	2,859.10	775.72	291.87
Arkansas	602.00	486.38	280.15	280.15
Louisiana	91,543.91	71,989.49	26,525.22	17,858.76
Mississippi	630.03	163.32	60.00	15.80
Texas	183,416.49	122,312.29	72,737.12	46,983.18
Wyoming	120.00	21.06	73,777.00	70,745.32
All other states	320.00	266.66	160.00	17.32
Offshore Louisiana	4,609.37	276.56	5,000.00	258.34
Offshore Texas	14,400.00	1,600.79	—	—
Total Domestic	305,327.81	199,975.65	179,315.21	136,450.74
New Zealand	6,760.00	6,454.00	163,262.37	112,652.01
Total	312,087.81	206,429.65	342,577.58	249,102.75

[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 83,920 undeveloped fee mineral acres for a total of 110,265 fee mineral acres.

Drilling Activities

The following table sets forth the results of our drilling activities during the three years ended December 31, 2002:

		Gross Wells				Net Wells			
Year	Type of Well	Total	Producing	Dry	Temporarily Abandoned	Total	Producing	Dry	Temporarily Abandoned
2000	Exploratory–Domestic	9	5	4	—	6.2	3.4	2.8	—
	Development–Domestic	59	52	7	—	42.4	37.1	5.3	—
	Exploratory–New Zealand	2	2	—	—	1.8	1.8	—	—
2001	Exploratory–Domestic	11	6	5	—	6.2	4.0	2.2	—
	Development–Domestic	36	36	—	—	29.5	29.5	—	—
	Exploratory–New Zealand	2	—	1	1	1.1	—	0.9	0.2
	Development–New Zealand	4	2	2	—	3.6	1.8	1.8	—
2002	Exploratory–Domestic	7	3	4	—	5.0	2.3	2.7	—
	Development–Domestic	23	17	6	—	23.0	17.0	6.0	—
	Exploratory–New Zealand	3	2	1	—	2.2	2.0	0.2	—
	Development–New Zealand	3	2	1	—	3.0	2.0	1.0	—

Operations

We generally seek to be operator in the wells in which we have a significant economic interest. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. We do not own drilling rigs or other oil field services equipment used for drilling or maintaining wells on properties we operate. Independent contractors supervised by us provide all the 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 gas. The fees for these activities paid to us in 2002 totaled $5.0 million and ranged from $450 to $2,174 per well per month.

Marketing of Production

Domestically, we typically sell our oil and gas production at market prices near the wellhead, although in some cases it must be gathered and delivered to a central point. Gas production is sold in the spot market on a monthly basis, while we sell our oil production at prevailing market prices. We do not refine any oil we produce. Eastex Crude Company and Contact Energy in New Zealand each accounted for 10% or more of our total revenues during the year ended December 31, 2002, with those purchasers accounting for approximately 28% of revenues in the aggregate. For the year ended December 31, 2001, Eastex Crude Company and subsidiaries of Enron accounted for approximately 29% of our total revenues. However, due to the 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.

In 1998, we entered into gas processing and gas transportation agreements for our 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, both affiliates of El Paso Merchant Energy, for up to 75,000 Mcf per day, which provided for a ten-year term with automatic one-year extensions unless earlier terminated. We believe that these arrangements adequately provide for our gas transportation and processing needs in the AWP Olmos Area for the foreseeable future. Additionally, the gas processed and transported under these agreements may be sold to El Paso based upon current natural gas prices.

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

Our oil production from the Lake Washington Area is delivered into ExxonMobil's crude oil pipeline system for sales to various purchasers at prevailing market prices. Our 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.

Our oil production in New Zealand is sold into the international market at prices tied to the Asia Petroleum Price Index (APPI) Tapis posting, less the cost of storage, trucking, and transportation.

Our gas production from our TAWN fields is sold under a long-term contract with Contact Energy. Our gas production from the Rimu field is sold to Genesis Power Ltd. under a long-term contract. Additional production volumes from our TAWN fields, over the contract minimum, can be sold to Contact Energy or Genesis Power Ltd. at prevailing market rates.

Our New Zealand natural gas liquids production is sold to RockGas 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 gas production for the three-year period ended December 31, 2002. "Net" production is production that is owned by us directly or indirectly through partnerships or joint venture interests and is produced to our interest after deducting royalty, limited partner, and other similar interests.

	Year Ended December 31,		
	2002	2001	2000
Net Sales Volume:			
Oil (Bbls)[1]	3,770,128	3,055,373	2,472,014
Gas (Mcf)[2,3]	27,131,578	26,458,958	27,524,621
Gas equivalents (Mcfe)	49,752,346	44,791,202	42,356,705
Average Sales Price:			
Oil (per Bbl)[1]	$ 20.88	$ 22.64	$ 29.35
Gas (per Mcf)[3]	$ 2.30	$ 4.23	$ 4.24
Average Production Cost (per Mcfe)	$ 0.83	$ 0.82	$ 0.69

[1]Oil production for 2002 includes New Zealand production of 695,454 barrels, at an average price per barrel of $20.28. Oil production for 2001 includes New Zealand production of 84,261 barrels, at an average price per barrel of $21.64.

[2]Natural gas production for 2000 includes 405,130 Mcf delivered under the volumetric production payment agreement pursuant to which we were obligated to deliver certain monthly quantities of natural gas. Under the volumetric production payment entered into in 1992, we delivered the last remaining commitment of gas in October 2000, when such agreement expired.

[3]Natural gas production for 2002 includes New Zealand production of 11,351,518 Mcf, with an average price of $1.32 per Mcf.

In the table above, for 2002, natural gas liquids have been combined with oil and condensate for reporting purposes. The natural gas liquids production for 2002 was 1,173,504 barrels, at an average price of $12.82 per barrel.

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, oil spills, and fires, 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. Additionally, as managing general partner of limited partnerships, we are solely responsible for the day-to-day conduct of the limited partnerships' affairs and accordingly have liability for expenses and liabilities of the limited partnerships. We maintain comprehensive insurance coverage, including general liability insurance in an amount not less than $50.0 million, as well as general partner liability insurance. We believe that our insurance is adequate and customary for companies of a similar size engaged in comparable operations, but losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage.

Employees

At December 31, 2002, we employed 234 persons. Of these employees, 57 are in New Zealand, eight of whom are members of a union. None of our other employees are represented by a union. Relations with employees are considered to be good.

Partnerships

Prior to 1995, we funded a substantial portion of our operations through 109 limited partnerships which we formed and for which we have served as managing general partner. These partnerships raised a total of $509.5 million of capital, with the largest portion (81%) raised to acquire interests in producing properties. Eight of the earliest partnerships and 13 of the most recently formed partnerships were created to drill for oil and gas. In all of these partnerships Swift paid for varying percentages of the capital or front-end costs and continuing costs of the partnerships and, in return, received differing percentage ownership interests in the partnerships, along with reimbursement of costs and/or payment of certain fees. These partnerships began liquidating and selling their properties in 1996. At year-end 2002, we continued to serve as managing general partner for six remaining partnerships, all of which are drilling partnerships that have been in existence from four to six years.

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.

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.

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

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

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

MBbl — Thousand barrels of oil.

Mcf — Thousand cubic feet of natural gas.

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

MMBbl — Million barrels of oil.

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

MMcf — Million cubic feet of natural gas.

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

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.

Petajoules — A unit of energy equivalent to .95 Bcf of 1,000 Btu of natural gas.

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. Proved undeveloped oil and gas reserves are 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.

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.

Terajoule — A unit of energy equivalent to 1,000 gigajoules.

Volumetric Production Payment — The 1992 agreement pursuant to which we financed the purchase of certain oil and natural gas interests and committed to deliver certain monthly quantities of natural gas.

Those portions (other than Items 10-13 incorporated by reference to Swift's proxy statement for its 2003 Annual Meeting of Shareholders) of the Form 10-K Report for the year ended December 31, 2002, not included in this Annual Report to Shareholders (including certain portions of Item 1–Business pertaining to "Competition," "Regulations," and "Facilities," Item 3–Legal Proceedings, Item 4–Submission of Matters to a Vote of Security Holders, Item 9–Changes in and Disagreements with Accountants on Accounting and Financial Disclosure, Item 14–Controls and Procedures, 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 Investor Relations, Swift Energy Company, 16825 Northchase Drive, Suite 400, Houston, Texas 77060-6098. 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.

Investor Information

BOARD OF DIRECTORS

A. Earl Swift
Chairman of the Board
Swift Energy Company

Virgil N. Swift
Vice Chairman of the Board
Swift Energy Company
Chairman, Swift Energy International

Terry E. Swift
President & CEO
Swift Energy Company
President, Swift Energy International

G. Robert Evans
Retired Chairman & CEO
Material Sciences Corporation

Raymond E. Galvin
Retired President
Chevron U.S.A.
Production Company

Henry C. Montgomery
Chairman & Founder
Montgomery Financial
Services Corporation

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

Harold J. Withrow
Consultant

Raymond O. Loen
Director Emeritus

OFFICERS

Terry E. Swift
President & Chief Executive Officer

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

Bruce H. Vincent
Executive Vice President–Corporate
Development, Secretary

Alton D. Heckaman, Jr.
Senior Vice President–Finance,
Chief Financial Officer

James M. Kitterman
Senior Vice President–Operations

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

Victor R. Moran
Senior Vice President–Energy
Marketing & Business Development

Gerald B. Long
Vice President–Production
Operations

Khushroo N. J. Patel
Vice President–Geophysics

Thomas E. Schmidt
Vice President–Exploration &
Development

Tara L. Seaman
Vice President–Acquisitions,
Dispositions & Reserves

Adrian D. Shelley
Treasurer

David W. Wesson
Controller

D. Wynn Ibach
General Counsel

CORPORATE HEADQUARTERS

Swift Energy Company
16825 Northchase Drive, Suite 400
Houston, Texas 77060-6098
Telephones: (281) 874-2700
(800) 777-2412

PRINCIPAL SUBSIDIARY COMPANIES

Swift Energy International, Inc.
Houston, Texas

SWENCO-Western, Inc.
Houston, Texas

Swift Energy Marketing Company
Houston, Texas

GASRS, Inc.
Houston, Texas

TRANSFER AGENT AND REGISTRAR

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

EXCHANGE LISTINGS

New York Stock Exchange
Pacific Exchange, Inc.
Symbol "SFY"

INDEPENDENT ACCOUNTANTS

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

COUNSEL

Jenkens & Gilchrist
A Professional Corporation
1100 Louisiana, Suite 1800
Houston, Texas 77002

COMMON STOCK, 2001 AND 2002

Our common stock is traded on the New York Stock Exchange and the Pacific Exchange, Inc., under the symbol "SFY." The high and low quarterly sales prices for the common stock for 2001 and 2002 were as follows:

	2001				2002			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Low	$28.91	$27.70	$19.00	$16.66	$15.55	$13.44	$10.40	$6.80
High	$37.50	$37.70	$32.55	$25.14	$20.58	$20.53	$15.23	$10.54

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

We had approximately 366 stockholders of record as of December 31, 2002.

Annual Meeting
4 p.m., Tuesday, May 13, 2003
The Wyndham Greenspoint Hotel
12400 Greenspoint Dr.
Houston, Texas 77060-1998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