SWIFT ENERGY CO
Form 424B2
April 10, 2002

FILED PURSUANT TO RULE 424(b)(2)
REGISTRATION NO. 333-64692

PROSPECTUS SUPPLEMENT TO PROSPECTUS DATED JULY 23, 2001

1,500,000 Shares

[SWIFT LOGO]

Common Stock

Our common stock is listed on the New York Stock Exchange and Pacific Stock Exchange under the symbol "SFY." The last reported sale price of our common stock on the New York Stock Exchange on April 8, 2002 was $19.45 per share.

The underwriter has an option to purchase a maximum of 225,000 additional shares from us to cover over-allotments of shares.

INVESTING IN OUR COMMON STOCK INVOLVES RISKS. SEE "RISK FACTORS" BEGINNING ON PAGE S-10 OF THIS PROSPECTUS SUPPLEMENT AND ON PAGE 2 OF THE ACCOMPANYING PROSPECTUS.

	PRICE TO PUBLIC	UNDERWRITING DISCOUNTS AND COMMISSIONS	PROCEED SWIFT E COMPA
Per Share.......................................	$18.25	$0.50	$17.
Total...	$27,375,000	$750,000	$26,625

Delivery of the shares of common stock will be made on or about April 12, 2002.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved these securities or determined if this prospectus supplement or the accompanying prospectus to which it relates is truthful or complete. Any representation to the contrary is a criminal offense.

CREDIT SUISSE FIRST BOSTON

The date of this prospectus supplement is April 9, 2002

This document is in two parts. The first part is this prospectus supplement, which describes the terms of the offering of common stock. The second part is the accompanying prospectus, which gives more general information, some of which may not apply to the common stock. In this prospectus supplement, "Swift," "we," "us," and "our" refer to Swift Energy Company and its subsidiaries, unless otherwise indicated.

YOU SHOULD RELY ONLY ON THE INFORMATION WE HAVE INCLUDED OR INCORPORATED BY REFERENCE IN THIS PROSPECTUS SUPPLEMENT AND THE ACCOMPANYING PROSPECTUS. WE HAVE

NOT AUTHORIZED ANYONE TO PROVIDE YOU WITH ADDITIONAL OR DIFFERENT INFORMATION. IF YOU RECEIVE ANY UNAUTHORIZED INFORMATION, YOU MUST NOT RELY ON IT. WE ARE OFFERING TO SELL THE COMMON STOCK ONLY IN STATES WHERE SALES ARE PERMITTED. YOU SHOULD NOT ASSUME THAT THE INFORMATION WE HAVE INCLUDED IN THIS PROSPECTUS SUPPLEMENT OR THE ACCOMPANYING PROSPECTUS IS ACCURATE AS OF ANY DATE OTHER THAN THE DATE OF THIS PROSPECTUS SUPPLEMENT OR THE ACCOMPANYING PROSPECTUS OR THAT ANY INFORMATION WE HAVE INCORPORATED BY REFERENCE IS ACCURATE AS OF ANY DATE OTHER THAN THE DATE OF THE DOCUMENT INCORPORATED BY REFERENCE.

See the "Glossary of Terms" beginning on page S-54 for explanations of abbreviations and terms used in this prospectus supplement.

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INCORPORATION OF ADDITIONAL DOCUMENTS BY REFERENCE

In addition to the documents referred to under "Where You Can Find More Information" in the accompanying prospectus, this prospectus supplement incorporates by reference our Annual Report on Form 10-K for the fiscal year ended December 31, 2001 filed by us with the Securities and Exchange Commission.

SUMMARY

This summary highlights selected information from this prospectus supplement and the accompanying prospectus, but may not contain all of the information that is important to you. This prospectus supplement and the accompanying prospectus include specifics of the offering of our common stock and information about our business and financial data. Before making an investment decision, we encourage you to read this prospectus supplement and the accompanying prospectus, including the "Risk Factors" section in each prospectus, and the documents we incorporate by reference. When we describe our year end 2001 proved reserves on a pro forma basis, we are giving effect to our January 2002 acquisition of an estimated 62.1 Bcfe of proved reserves at year end 2001 in the TAWN fields in New Zealand and to our March 2002 acquisition of an estimated 5.7 Bcfe of proved reserves at year end 2001 in the Rimu/Kauri area in New Zealand from Antrim Oil and Gas Limited. Our actual year end 2001 proved reserves prior to the above acquisitions were 645.8 Bcfe. Unless otherwise indicated, this prospectus supplement assumes no exercise of the underwriter's over-allotment option.

ABOUT SWIFT

Swift Energy Company engages in developing, exploring, acquiring, and operating oil and gas properties, with a focus on onshore oil and natural gas reserves in Texas and Louisiana and onshore oil and natural gas reserves in New Zealand. At year end 2001, on a pro forma basis, we had estimated proved reserves of 713.6 Bcfe, concentrated 48% in Texas, 25% in Louisiana and 24% in

New Zealand. Approximately 52% of these reserves are natural gas. For the 12 months ended December 31, 2001, we generated EBITDA of $136.8 million.

The following table of pro forma proved reserves highlights our core areas:

AREA	LOCATION	PRO FORMA PROVED RESERVES AS OF YEAR END 2001: PROVED RESERVES (BCFE)	PERCENT OF PROVED RESERVES
AWP Olmos	South Texas	207.5	29%
Masters Creek	Central Louisiana	104.8	15%
Brookeland	East Texas	59.1	8%
Lake Washington	South Louisiana	72.5	10%
Rimu/Kauri	New Zealand	107.6	15%
TAWN	New Zealand	62.1	9%
Other Domestic		100.0	14%
Total		713.6	100%

We have a well-balanced portfolio of oil and gas properties and prospects. The AWP Olmos, Lake Washington and New Zealand areas are characterized by long-lived reserves that we expect to produce steadily 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 more rapidly. Based on 2001 year end domestic proved reserves and 2001 production, our domestic properties had an estimated average reserve life of 12.3 years. An independent engineering firm's report in late 2001 estimates the Rimu/Kauri development area to have a 25-30 year life. In addition to our core areas, we have a number of emerging growth areas that may become additional core operating areas for us. These growth areas are described in the "Business and Properties" section of this prospectus supplement.

RECENT DEVELOPMENTS

Effective January 25, 2002, we expanded our core areas of operation by acquiring interests in the four TAWN fields in New Zealand for approximately $54.4 million. This acquisition, which also included significant infrastructure, added proved developed reserves estimated to be 62.1 Bcfe at December 31, 2001, all of which are proved producing and approximately 75% of which were classified as natural gas. In March 2002, we purchased an additional 5% interest in our permit 38719, where the Rimu and Kauri discoveries are located, from Antrim Oil and Gas Limited for 220,000 shares of Swift common stock and

an effective date adjustment of approximately $530,000. This acquisition added estimated reserves at year end 2001 of 5.7 Bcfe and increased our interest in the permit to 95%. We also acquired Antrim's interest in another New Zealand permit, which doubled our interest there to 15%. In addition, the construction of our Rimu production station in New Zealand has been completed, which will allow us to commence sale of production from our Rimu discovery in April 2002.

Since acquiring the Lake Washington field in March 2001, we have drilled a total of eight wells in this field. The results of these wells support our belief that there is additional reserves potential in multiple horizons located around the salt dome in the center of the field ranging from depths of 1,300 to

18,000 feet. We have increased average monthly production in this field net to Swift's interests from approximately 652 BOE per day when we acquired the field to approximately 1,236 BOE per day during February 2002. The field currently produces oil and natural gas liquids from 26 wells. As a result of our drilling and remapping of the field and improvement in production levels, we are currently focusing most of our 2002 domestic drilling budget on 20 development wells and two exploratory wells in this field. We have 29 proved undeveloped drilling locations in this field.

Our first quarter 2002 production increased over 17.5% to at least 12.1 Bcfe compared to production of 10.3 Bcfe during the first quarter of 2001. This is also a 5% increase from 11.5 Bcfe produced during the fourth quarter of 2001. Approximately 20% of the first quarter 2002 production comes from our new TAWN core area in New Zealand.

On March 28, 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 Russian joint stock company, which owned and operated this field. This cash payment will result in our recognition of a $7.5 million non-recurring pre-tax gain in the first quarter of 2002.

In late March and early April 2002, we entered into hedges covering a portion of both our oil and natural gas production from May 2002 through December 2002. These hedges are in the form of participating collars that are a series of puts and calls, in which we will participate in 60% of the price received above the cap. The counter party to the gas contracts is a member of our bank syndicate under our credit facility and another member is the counter party to the oil contracts. One group of oil collars has a floor of $20.00 per Bbl and a cap of $27.52 per Bbl and covers 25,000 Bbl per month, and the other group has a floor of $21.00 per Bbl and a cap of $27.65 and covers 20,000 Bbl per month. One group of natural gas collars has a floor of $2.50 per MMBtu and a cap of $4.21 per MMBtu and covers 200,000 MMBtu per month of our domestic production, and the other group has a floor of $2.75 per MMBtu and a cap of $4.55 per MMBtu and covers 80,000 MMBtu per month of our domestic production. All of our New Zealand natural gas production for 2002 is contracted for at defined prices under two long-term, reserve-based contracts.

We have filed a preliminary prospectus supplement dated April 1, 2002 with the SEC relating to the offering of $150.0 million of senior subordinated notes due 2012. These notes will be offered in a separate public offering pursuant to a separate prospectus supplement. The indenture to be executed in conjunction with the notes offering will contain substantially the same covenants as in our existing 10.25% Senior Subordinated Notes Due 2009. See "Description of Existing Indebtedness -- Senior Subordinated Notes Due 2009." Our notes offering is expected to close in mid-April 2002, although we can provide no assurance in this regard. This offering of common stock and the notes offering are not conditioned upon each other.

On April 8, 2002, Moody's Investors Service announced it had assigned a B3 rating to our proposed $150.0 million senior subordinated notes offering. In connection with this rating, Moody's announced further that it had changed the rating of our existing $125.0 million of 10.25% senior subordinated notes due 2009 to B3, down from B2.

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COMPETITIVE STRENGTHS AND BUSINESS STRATEGY

SUCCESSFUL TRACK RECORD

Our growth in reserves and production has resulted primarily from drilling activities in our core areas combined with producing property acquisitions. Over the five-year period ended December 31, 2001, our estimated proved reserves grew from 258.7 Bcfe to 713.6 Bcfe on a pro forma basis. Over the same period, our net cash provided by operations increased from $37.1 million to $139.9 million. We believe that our experience in growing our reserves will be beneficial to us as we continue to pursue our business strategy.

BALANCED APPROACH TO ADDING RESERVES

Over the past five years, we have spent an average of 11% of our capital expenditure budget on exploration drilling, 51% on development activities, 19% on proved property acquisitions and 14% on lease acquisitions. Currently our 2002 capital expenditures are focused on developing and producing long-lived reserves in Lake Washington and New Zealand, which should flatten our overall production decline curve, strengthen our ongoing production profile and extend our average reserve life. Our strategy is to grow through drilling on our core properties and in emerging growth areas when oil and gas prices are strong, with a shift toward acquisitions when prices weaken. 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. Over the five-year period ended December 31, 2001, we replaced 302% of our production at an average cost of $1.26 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. Our domestic operations are concentrated in Texas and Louisiana, where 96% of our domestic reserves are located. All of our international operations are currently concentrated in New Zealand. We enhance the value of these concentrations by acting as operator of 95% of our proved reserves at year end 2001. Our focus in our core areas has enabled us to develop and utilize several innovative technology applications adapted to those areas, which we believe provide us with an advantage over our competitors.

ABILITY TO BUILD UPON OUR SUCCESSFUL 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. In April 2001, we began selling oil from extended production testing of our New Zealand wells. We expect production and gas processing facilities will be operational in April 2002, a significantly faster period from initial discovery to commercial production than similar projects previously conducted in New Zealand of which we are aware. In January 2002, we acquired the TAWN fields. From the closing of the TAWN acquisition on January 25, 2002 through March 25, 2002, these fields have generated average daily net production of approximately 40 MMcfe. 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 access to export terminals and markets and additional excess processing capacity for both oil and natural gas. We also have prospective areas in New Zealand outside of the Rimu/Kauri area that we will evaluate for drilling in the future.

EXPERIENCED TECHNICAL TEAM

We employ 35 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. This level of expertise and experience, coupled with our employees' longevity with Swift, gives us a unique in-house ability to apply advanced technologies to our drilling, acquisition and production activities.

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 balanced capital budget, establishing leverage ratios that are appropriate given the volatility of the oil and gas markets and opportunistically accessing the capital markets. After giving effect to this offering, as of December 31, 2001, our long-term debt would have comprised approximately 41% of our total capitalization, or 45% after giving further effect to the proposed notes offering. As of February 28, 2002, after the TAWN acquisition in January 2002, and after giving effect to the Antrim acquisition in March 2002 and this offering, our long-term debt would have comprised approximately 48% of our total capitalization, which remains the same after giving further effect to the proposed notes offering. Additionally, after applying the net proceeds from this offering to reduce amounts outstanding under our credit facility, based on our February 28, 2002 balance, we expect to have approximately $81.3 million of available borrowing capacity, or $167.0 million after giving further effect to the proposed notes offering. By replacing indebtedness incurred under our revolving credit facility in connection with acquisition, development and exploitation activity with the net proceeds from this offering and the proposed notes offering, we will be implementing our strategy of matching long-lived assets with long-term debt and equity.

THE OFFERING

Common stock offered..........	1,500,000 shares
Common stock to be outstanding after the offering...........	26,612,636 shares
Use of proceeds..............	The net proceeds of this offering are estimated to be approximately $26.5 million. The net proceeds will be used to reduce the outstanding indebtedness under our credit facility incurred in connection with our recent acquisition, development and exploration activities.
New York Stock Exchange and Pacific Stock Exchange Symbol......................	"SFY"

The number of shares shown above to be outstanding after the offering does not include 2,639,504 shares that may be issued upon exercise of options outstanding under our stock compensation plans outstanding as of December 31, 2001.

RISK FACTORS

Before making an investment decision, you should consider all of the information in this prospectus supplement and the accompanying prospectus, and should carefully evaluate the risks in the "Risk Factors" section beginning on page S-10 of this prospectus supplement and page 2 of the accompanying prospectus.

SUMMARY CONSOLIDATED FINANCIAL DATA

The summary consolidated financial data presented below for each of the five years in the period ended December 31, 2001 has been derived from our audited consolidated financial statements. For a discussion of our significant financial results and conditions during 2001, 2000 and 1999, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this prospectus supplement.

	YEAR ENDED DECEMBER 3			
	2001	2000	1999	
		(IN THOUSANDS, EXCEPT RA		
INCOME STATEMENT DATA:				
Revenues:				
Oil and gas sales	$181,185	$189,139	$108,899	$
Fees from limited partnerships and joint ventures	427	332	230	
Interest income	49	1,339	833	
Price risk management and other, net	2,146	815	709	
Total revenues	183,807	191,625	110,671	
Costs and expenses:				
General and administrative, net of reimbursement	8,187	5,586	4,497	
Depreciation, depletion, and amortization	59,502	47,771	42,349	
Oil and gas production	36,720	29,221	19,646	
Interest expense, net	12,627	15,968	14,443	
Other expenses	2,102	--	--	
Write-down of oil and gas properties(a)	98,862	--	--	
Total costs and expenses	218,000	98,546	80,935	1
Income (loss) before income taxes and extraordinary item and change in accounting principle	(34,193)	93,079	29,736	(
Provision (benefit) for income taxes	(12,238)	33,265	10,450	(
Income (loss) before extraordinary item and change in accounting principle	(21,955)	59,814	19,286	(
Extraordinary loss on early extinguishment of debt (net of taxes)(b)	--	630	--	
Cumulative effect of change in accounting principle (net of taxes)(c)	393	--	--	
Net income (loss)	$(22,348)	$ 59,184	$ 19,286	$(
OTHER FINANCIAL DATA:				
EBITDA(d)	$136,799	$156,819	$ 86,528	$
Net cash provided by operating activities	139,884	128,197	73,603	
Capital expenditures	275,126	173,277	78,113	1
BALANCE SHEET DATA (AT END OF PERIOD):				
Working capital (deficit)	$(36,492)	$(22,452)	$ 16,535	$
Total assets	671,685	572,387	454,299	4
Long-term debt:				

Bank borrowings	134,000	10,600	--	1
6.25% convertible subordinated notes	--	--	115,000	1
10.25% senior subordinated notes	124,197	124,129	124,068	
Stockholders' equity	312,653	332,154	170,404	1

(Notes

NOTES TO SUMMARY CONSOLIDATED FINANCIAL DATA

(a) In the fourth quarter of 2001, prices for both oil and gas at December 31, 2001, necessitated a pre-tax domestic full cost ceiling write-down of oil and gas properties of $98.9 million, or $63.5 million after-tax. Additionally, in the third quarter of 1998, we took a non-cash write-down of domestic oil and gas properties as lower prices for both oil and gas at September 30, 1998, necessitated a pre-tax domestic full cost ceiling write-down in 1998 of $77.2 million, or $50.9 million after-tax. Also in the third quarter of 1998, we impaired our total investment in Russia of $10.8 million and impaired our capitalized unproved properties costs in Venezuela of $2.8 million. The impairment of the unproved properties costs in these two countries resulted in a separate 1998 non-cash pre-tax charge to earnings of $13.6 million, or $9.0 million after-tax. The combination of the non-cash full cost domestic ceiling write-down and the non-cash foreign impairment charges in 1998 resulted in a combined non-cash charge to earnings of $90.8 million pre-tax, or $59.9 million after-tax.

(b) In December 2000, we called for redemption of all our 6.25% Convertible Subordinated Notes due 2006, or Convertible Notes, 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 approximately $15.0 million remaining 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.

(c) We adopted SFAS No. 133 effective January 1, 2001. Accordingly, we marked our open derivative contracts at December 31, 2000 to fair value at that date resulting in a one-time net of taxes charge of $0.4 million which is recorded as a cumulative effect of change in accounting principle.

(d) EBITDA represents income before interest expense, income tax, and depreciation, depletion and amortization (including the write-down of oil and gas properties). We have reported EBITDA because we believe EBITDA is a measure commonly reported and widely used by investors as an indicator of a company's operating performance. We believe EBITDA assists such investors in comparing a company's performance on a consistent basis without regard to depreciation, depletion and amortization, which can vary significantly depending upon accounting methods or nonoperating factors such as historical cost. EBITDA is not a calculation based on GAAP and should not be considered an alternative to net income in measuring our performance or used as an exclusive measure of cash flow because it does not consider the impact of working capital growth, capital expenditures, debt principal reductions and other sources and uses of cash which are disclosed in our Consolidated Statements of Cash Flows. Investors should carefully consider the specific items included in our computation of EBITDA. While EBITDA has been disclosed herein to permit a more complete comparative analysis of our operating performance relative to other companies, investors should be cautioned that EBITDA as reported by us may not be comparable in all instances to EBITDA as reported by other companies. EBITDA amounts may not be fully available for management's discretionary use, due to certain requirements to conserve funds for capital expenditures, debt service and other commitments.

SUMMARY RESERVES AND PRODUCTION DATA

The following tables set forth certain summary information with respect to estimates of our oil and gas reserves, and data about production and sales of oil and gas for the periods indicated. Reserves were determined by us and audited by H.J. Gruy and Associates, Inc., independent petroleum consultants. The net reserves and cash flows for New Zealand were prepared by us. See "Business and Properties -- Oil and Gas Reserves" and "Risk Factors."

	AS OF AND FOR THE YEAR ENDED D		
	2001	2000	1999
ESTIMATED PROVED OIL AND GAS RESERVES(A):			
Net gas reserves (MMcf):			
Proved developed	181,652	215,170	174,046
Proved undeveloped	143,260	203,444	155,914
Total	324,912	418,614	329,960
Net oil reserves (MBbls):			
Proved developed	23,760	10,980	8,437
Proved undeveloped	29,723	24,154	12,369
Total	53,483	35,134	20,806
TOTAL PROVED OIL AND GAS RESERVES (MMCFE)	645,808	629,416	454,797
ESTIMATED PRESENT VALUE OF PROVED RESERVES (IN THOUSANDS):			
Estimated present value of future net cash flows from proved reserves discounted at 10% per annum, "PV-10 Value"(a):			
Proved developed	$ 344,479	$1,257,571	$301,200
Proved undeveloped	258,507	1,055,684	262,855
PV-10 Value(a)	$ 602,986(b)	$2,313,255(b)	$564,055
Standardized measure of discounted estimated future net cash flows after income taxes(a)	$ 454,558	$1,577,958	$438,944
PRICES USED IN CALCULATING END OF YEAR PROVED RESERVES:			
Oil (per Bbl)	$ 18.45	$ 24.62	$ 23.69
Gas (per Mcf)	$ 2.51	$ 9.86	$ 2.58
OTHER RESERVES DATA:			
Three year reserve replacement cost (per Mcfe)(c)	$ 1.40	$ 1.00	$ 1.09
Three year reserve replacement rate(d)	263%	319%	287%
Gas as percent of total proved reserve quantities	50%	67%	73%
Proved developed reserves as percent of total proved reserves	50%	45%	49%

	YEAR ENDED DECEMBER 3		
	2001	2000	1999
NET SALES VOLUME:			
Oil (MBbls)	3,055	2,472	2,565
Gas (MMcf)(e)	26,459	27,525	27,485
Total production (MMcfe)(e)	44,791	42,357	42,874
WEIGHTED AVERAGE SALES PRICES:			
Oil (per Bbl)	$ 22.64	$ 29.35	$ 16.75
Gas (per Mcf)	$ 4.23	$ 4.24	$ 2.40
SELECTED DATA PER MCFE:			
Production costs	$ 0.82	$ 0.69	$ 0.46
Depreciation, depletion, and amortization	$ 1.33	$ 1.13	$ 0.99
General and administrative, net of reimbursement	$ 0.18	$ 0.13	$ 0.10

(Not

NOTES TO SUMMARY RESERVES AND PRODUCTION DATA

(a) Quantity estimates, their PV-10 Value and the standardized measure of future net cash flows are affected by the change in crude oil and gas prices at the end of each year.

(b) Under SEC guidelines, estimates of the PV-10 Value of proved reserves must be made using oil and gas sales prices at the date for the valuation, which prices are held constant throughout the life of the properties. Our year end 2001 average prices used to calculate PV-10 Value were $2.51 per Mcf and $18.45 per Bbl. 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 was also lower than the average oil price of $22.64 we received in 2001. Had year end reserves been calculated using the average 2001 prices we received, $22.64 for oil and $4.23 for gas, the PV-10 Value would have been approximately $947.8 million compared to the $603.0 million reported using year end 2001 prices. Conversely, commodity prices were unusually high at year end 2000, especially gas prices. Our year end 2000 average prices used to calculate PV-10 Value were $9.86 per Mcf and $24.62 per Bbl. Had year end 2000 reserves been calculated using the average 2000 prices we received, $29.35 for oil and $4.24 for gas, the PV-10 Value would have been approximately $1.1 billion compared to the $2.3 billion reported using year end 2000 prices.

(c) Calculated for a three-year period ending with the year presented by dividing total acquisition, exploration and development costs, excluding future development costs, during such period by net reserves added during the period, excluding any revisions of those reserves.

(d) Calculated for a three-year period ending with the year presented by dividing the increase in net reserves, including any revisions of those reserves, by the production quantities for such period.

(e) Natural gas production for the years ended 2000, 1999, 1998 and 1997 includes 405, 728, 866 and 1,015 MMcf, respectively, delivered under the volumetric production payment agreement pursuant to which we were obligated to deliver certain monthly quantities of gas to a third party through October 2000. Remaining obligated volumes associated with the volumetric production payment were not included in our estimate of net reserves for the relevant years.

RISK FACTORS

An investment in our common stock involves significant risks. You should carefully consider the following risk factors before you decide to purchase our common stock. You should also carefully read and consider all of the information we have included, or incorporated by reference, in this prospectus supplement and the accompanying prospectus before you decide to purchase our common stock.

OIL AND NATURAL GAS PRICES ARE VOLATILE. A SUBSTANTIAL DECREASE IN OIL AND NATURAL GAS PRICES WOULD ADVERSELY AFFECT OUR FINANCIAL RESULTS.

Our future financial condition, results of operations and the value of our oil and natural gas properties depend primarily upon market prices for oil and natural gas. Oil and natural gas prices historically have been volatile and will likely continue to be volatile in the future. Oil and natural gas prices received in the second half of 2001 were significantly lower than the average prices we received during the first half of 2001, and lower than the average prices received for most of 2000. Both commodity prices continued to drop during the early part of the first quarter of 2002. The prices for oil and natural gas are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, worldwide economic conditions, weather conditions, import prices, political conditions in major oil producing regions, especially the Middle East, and actions taken by OPEC. A significant decrease in price levels for an extended period would negatively affect us in several ways:

- our cash flow would be reduced, decreasing funds available for capital expenditures employed to replace reserves or increase production;

- certain reserves would no longer be economic to produce, leading to both lower proved reserves and cash flow;

- our lenders could reduce the borrowing base under our credit facility because of lower oil and gas reserve values, reducing our liquidity and possibly requiring mandatory loan repayments; and

- access to other sources of capital, such as equity or long-term debt markets, could be severely limited or unavailable in a low price environment.

Consequently, our revenues and profitability would suffer.

OUR DEBT REDUCES OUR FINANCIAL FLEXIBILITY, AND OUR DEBT LEVELS MAY INCREASE.

As of February 28, 2002, after the TAWN acquisition in January 2002, and after giving effect to the Antrim acquisition in March 2002, to this offering and to the proposed notes offering, our long-term debt would have comprised approximately 48% of our total capitalization. Increased debt:

- would require us to dedicate a significant portion of our cash flow to the payment of interest;

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

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

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

Subject to restrictions in our credit facility and the indenture for our senior subordinated notes due 2009, as of February 28, 2002, we had a $300.0 million credit facility with a borrowing base of $275.0 million of which $54.8 million was available for borrowing. If we increase our debt levels further, the risks discussed above would become greater.

IF WE CANNOT REPLACE OUR RESERVES, OUR REVENUES AND FINANCIAL CONDITION WILL SUFFER.

Unless we successfully replace our reserves, our production will decline, resulting in lower revenues and cash flow. This is accentuated by the fact that in our Masters Creek area new production added by drilling has not kept up with the decline in production. When oil and gas prices decrease, our cash flow

decreases, resulting in less available cash to drill and replace our reserves and an increased need to draw on our bank line of credit.

DRILLING WELLS IS SPECULATIVE AND CAPITAL INTENSIVE.

Developing and exploring for oil and gas properties requires significant capital expenditures and involves a high degree of financial risk. The budgeted costs of drilling, completing and operating wells are often exceeded and can increase significantly when drilling costs rise. Drilling may be unsuccessful for many reasons, including title problems, weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of an oil or gas well does not ensure a profit on investment. Exploratory wells bear a much greater risk of loss than development wells. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their cost, unsuccessful wells can hurt our efforts to replace reserves.

ESTIMATES OF PROVED RESERVES ARE UNCERTAIN, AND REVENUES FROM PRODUCTION MAY VARY FROM EXPECTATIONS SIGNIFICANTLY.

The quantities and values of our proved reserves included in this prospectus supplement and in our documents we have incorporated by reference are only estimates and subject to numerous uncertainties. Estimates by other engineers might differ materially. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. These estimates depend on assumptions regarding quantities and production rates of recoverable oil and gas reserves, future prices for oil and gas, timing and amounts of development expenditures and operating expenses, all of which will vary from those assumed in our estimates. These variances may be significant. For example, in 2001 the net reduction in our estimate of proved reserves in New Zealand was approximately 37 Bcfe.

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

At December 31, 2001, approximately 50% of our estimated proved reserves were undeveloped. Recovery of undeveloped reserves generally requires significant capital expenditures and successful drilling operations. The reserve data assumes that we can and will make these expenditures and conduct these operations successfully, which may not occur.

WE INCURRED A WRITE-DOWN OF THE CARRYING VALUES OF OUR PROPERTIES IN THE FOURTH QUARTER OF 2001 AND COULD INCUR ADDITIONAL WRITE-DOWNS IN THE FUTURE.

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

We recorded an after-tax, non-cash charge during the fourth quarter of 2001 of $63.5 million. This write-down results in a charge to earnings and a reduction of shareholders' equity, but does not impact our cash flow from operating activities. Once incurred, write-downs are not reversible at a later date. If commodity prices continue to decline or if we have downward oil and gas revisions, we could incur additional write-downs in the future. See "Management's Discussion and Analysis of Financial Condition and Results of Operations -- Critical Accounting Policies -- Property and Equipment."

RESERVES ON PROPERTIES WE BUY MAY NOT MEET OUR EXPECTATIONS AND COULD CHANGE THE NATURE OF OUR BUSINESS.

Property acquisition decisions are based on various assumptions and subjective judgments that are speculative. Although available geological and geophysical information can provide information about the potential of a property, it is impossible to predict accurately a property's production and profitability. Furthermore, future acquisitions may change the nature of our operations and business. For example, an acquisition of producing properties containing primarily oil reserves could change our current emphasis on gas reserves.

In addition, we may have difficulty integrating future acquisitions into our operations, and they may not achieve our desired profitability objectives. Likewise, as is customary in the industry, we generally acquire oil and gas acreage without any warranty of title except through the transferor. In many instances, title opinions are not obtained if, in our judgment, it would be uneconomical or impractical to do so. Losses may result from title defects or from defects in the assignment of leasehold rights. While our current operations are primarily in Texas, Louisiana and New Zealand, we may pursue acquisitions of properties located in other geographic areas, which would decrease our geographical concentration, and could also be in areas in which we have no or limited experience.

WE MAY HAVE DIFFICULTY COMPETING FOR OIL AND GAS PROPERTIES OR SUPPLIES.

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

GOVERNMENTAL LAWS AND REGULATIONS ARE COSTLY AND COMPLEX, ESPECIALLY THOSE RELATING TO ENVIRONMENTAL PROTECTION.

Our exploration, production and marketing operations are subject to extensive laws and regulations at the international, federal, state and local levels. These laws and regulations affect the costs, manner and feasibility of our operations. As an owner and operator of oil and gas properties, we are subject to international, federal, state and local laws and regulations relating to discharge of materials into, and protection of, the environment. We have made and will continue to make significant expenditures in our efforts to comply with the requirements of these environmental laws and regulations, which may impose liability on us for the cost of pollution clean-up resulting from operations, subject us to penalties and liabilities for pollution damages and require suspension or cessation of operations in affected areas. Changes in or additions to laws and regulations regarding the protection of the environment could increase our compliance costs and might hurt our business.

We are subject to state and local laws and regulations domestically and are subject to New Zealand laws and regulations that impose permitting, reclamation, land use, conservation and other restrictions on our ability to drill and produce oil and natural gas. These laws and regulations can require well and facility sites to be closed and reclaimed. We frequently buy and sell interests in properties that have been operated in the past, and as a result of these transactions we may retain or assume clean-up or reclamation obligations for our own operations or those of third parties.

WE MAY BE EXPOSED TO FINANCIAL AND OTHER LIABILITIES AS THE GENERAL PARTNER IN 71 LIMITED PARTNERSHIPS.

We currently serve as the managing general partner of 71 limited partnerships, all but six of which are in the process of selling their properties and liquidating. We are contingently liable for our obligations as a general partner, including responsibility for day-to-day operations and any liabilities that cannot be repaid

from partnership assets or insurance proceeds. In the future, we may be exposed to litigation in connection with the partnerships.

INCREASED VOLATILITY OF OIL AND GAS PRICES CAN CAUSE SUDDEN CHANGES IN THE MARKET PRICE OF OUR COMMON STOCK.

Our quarterly results of operations may fluctuate significantly as a result of variations in oil and gas prices and production performance. In recent years, oil and gas price volatility has become increasingly severe. You can expect the market price of our common stock to decline when our quarterly results decline or at any time when events adverse to us or the industry occur. Our common stock price may decline to a price below the price you paid to purchase your shares of common stock in this offering.

OUR SHAREHOLDER RIGHTS PLAN, ARTICLES OF INCORPORATION AND BYLAWS DISCOURAGE UNSOLICITED TAKEOVER PROPOSALS AND COULD PREVENT YOU FROM REALIZING A PREMIUM FOR YOUR COMMON STOCK.

We have a stockholder rights plan that may have the effect of discouraging unsolicited takeover proposals. The rights issued under the stockholder rights plan would cause substantial dilution to a person or group that attempts to acquire us on terms not approved in advance by our board of directors. In addition, our articles of incorporation and bylaws contain provisions that may discourage unsolicited takeover proposals that stockholders may consider to be in their best interests. These provisions include:

- a classified board of directors;

- the ability of the board of directors to designate the terms of and issue new series of preferred stock;

- advance notice requirements for nominations for election of the board of directors; and

- requirements for approval of business combinations with interested parties.

Together these provisions and the rights plan may discourage transactions that otherwise could involve payment of a premium over prevailing market prices for your common stock.

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USE OF PROCEEDS

We estimate that the net proceeds from the sale of common stock in this offering will be approximately $26.5 million, or $30.5 million if the underwriter exercises its over-allotment option in full, after deducting underwriting discounts and commissions and estimated offering expenses.

We intend to use the net proceeds to repay a portion of the outstanding indebtedness under our credit facility and to use the funds then made available under our credit facility for capital expenditures, acquisitions, and general corporate purposes.

In January 2002, upon closing of the New Zealand TAWN acquisition, our credit facility increased from $250.0 million to $300.0 million and the borrowing base increased from $200.00 million to $275.0 million. At February 28, 2002, $220.2 million was outstanding under our credit facility at a weighted average interest rate of 3.53%. The amount available for borrowing is subject to a borrowing base determination that is recalculated at least every six months, and is subject to reduction upon the closing of the proposed notes offering. Our bank credit facility is described in more detail in the "Description of Existing Indebtedness" section of this prospectus supplement.

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CAPITALIZATION

The following table sets forth as of December 31, 2001:

- our historical capitalization;

- our capitalization as adjusted for the estimated net proceeds of $26.5 million from the sale of our common stock in this offering; and

- our capitalization as further adjusted for the estimated net proceeds of $145.7 million from the proposed notes offering.

Our proposed notes offering is expected to close in mid-April 2002, although we can provide no assurance in this regard. This table does not reflect the issuance of 220,000 shares of our common stock in March 2002 to acquire the New Zealand assets of Antrim Oil and Gas Limited or 2,639,504 shares that may be issued pursuant to outstanding stock compensation plans as of December 31, 2001. This table should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations," the consolidated financial statements, and the related notes contained in this prospectus supplement.

	AS OF DECEMBER 31, 2001		
	HISTORICAL	AS ADJUSTED SOLELY FOR COMMON STOCK OFFERING	AS ADJUSTED FOR BOTH COMMON STOCK AND NOTES OFFERINGS
	(IN THOUSANDS, EXCEPT SHARE DATA)		
Cash and cash equivalents(a)	$ 2,149	$ 2,149	$ 40,389
Long-Term Debt			
Bank Borrowings(a)	134,000	107,500	--
10.25% Senior Subordinated Notes Due 2009	124,197	124,197	124,197
% Senior Subordinated Notes Due 2012	--	--	150,000
Total Long-Term Debt	$258,197	$231,697	$274,197
Stockholders' Equity			
Preferred stock, $.01 par value, 5,000,000 shares authorized, none outstanding	--	--	--
Common stock, $.01 par value, 85,000,000 shares authorized, 25,634,598 and 27,134,598 shares issued and 24,795,564 and 26,295,564 shares outstanding, respectively, as adjusted for the common stock offering	257	272	272
Additional paid-in capital	296,173	323,658	322,658
Treasury stock held, at cost, 839,034 shares	(12,033)	(12,033)	(12,033)
Retained Earnings	28,256	28,256	28,256
Total stockholders' equity	312,653	339,153	339,153
Total Capitalization	$570,850	$570,850	$613,350

(a) As of February 28, 2002, our outstanding bank borrowings were $220.2 million. Accordingly, after repaying a portion of amounts outstanding with the net proceeds from this offering, our bank borrowings as of February 28, 2002 would have been approximately $193.7 million, and our cash and cash equivalents would have been approximately $2.1 million. After repaying a portion of amounts outstanding with the net proceeds expected from the proposed notes offering, these amounts would have been approximately $48.0 million and $2.1 million, respectively.

COMMON STOCK PRICE RANGE AND DIVIDEND POLICY

Our common stock is traded on the New York and Pacific Stock Exchanges under the symbol "SFY." The following table sets forth the range of high and low sale prices per share of our common stock as reported by the NYSE for the periods indicated.

	HIGH	LOW
1999		
First Quarter	$ 8.63	$ 5.69
Second Quarter	13.13	8.25
Third Quarter	13.13	10.25
Fourth Quarter	13.31	10.31
2000		
First Quarter	$17.88	$ 9.75
Second Quarter	29.56	15.00
Third Quarter	41.88	20.38
Fourth Quarter	43.50	28.81
2001		
First Quarter	$37.50	$28.91
Second Quarter	37.70	27.70
Third Quarter	32.55	19.00
Fourth Quarter	25.14	16.66
2002		
First Quarter	$21.25	$15.39
Second Quarter (through April 9)	20.90	17.95

The last sale price of our common stock as reported by the New York Stock Exchange on April 9, 2002, was $18.10 per share.

We have not paid cash dividends on our common stock in the past and do not intend to pay dividends on our common stock in the foreseeable future. Our credit facility and the indenture governing our outstanding 10.25% notes due 2009 limit our ability to pay dividends.

SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The selected historical consolidated financial data presented below for each of the five years in the period ended December 31, 2001 has been derived from our audited consolidated financial statements. For a discussion of our significant financial results and conditions during 2001, 2000 and 1999, see "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this prospectus supplement.

	YEAR ENDED DECEMBER 3		
	2001	2000	1999
	(IN THOUSANDS, EXCEPT RA		

INCOME STATEMENT DATA:				
Revenues:				
Oil and gas sales	$181,185	$189,139	$108,899	$
Fees from limited partnerships and joint ventures	427	332	230	
Interest income	49	1,339	833	
Price risk management and other, net	2,146	815	709	
Total revenues	183,807	191,625	110,671	
Costs and expenses:				
General and administrative, net of reimbursement	8,187	5,586	4,497	
Depreciation, depletion, and amortization	59,502	47,771	42,349	
Oil and gas production	36,720	29,221	19,646	
Interest expense, net	12,627	15,968	14,443	
Other expenses	2,102	--	--	
Write-down of oil and gas properties(a)	98,862	--	--	
Total costs and expenses	218,000	98,546	80,935	1
Income (loss) before income taxes and extraordinary item and change in accounting principle	(34,193)	93,079	29,736	(
Provision (benefit) for income taxes	(12,238)	33,265	10,450	(
Income (loss) before extraordinary item and change in accounting principle	(21,955)	59,814	19,286	(
Extraordinary loss on early extinguishment of debt (net of taxes)(b)	--	630	--	
Cumulative effect of change in accounting principle (net of taxes)(c)	393	--	--	
Net income (loss)	$(22,348)	$ 59,184	$ 19,286	$(
OTHER FINANCIAL DATA:				
EBITDA(d)	$136,799	$156,819	$ 86,528	$
Net cash provided by operating activities	139,884	128,197	73,603	
Capital expenditures	275,126	173,277	78,113	1
BALANCE SHEET DATA (AT END OF PERIOD):				
Working capital (deficit)	$(36,492)	$(22,452)	$ 16,535	$
Total assets	671,685	572,387	454,299	4
Long-term debt:				
Bank borrowings	134,000	10,600	--	1
6.25% convertible subordinated notes	--	--	115,000	1
10.25% senior subordinated notes	124,197	124,129	124,068	
Stockholders' equity	312,653	332,154	170,404	1

(Notes

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NOTES TO SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

(a) In the fourth quarter of 2001, prices for both oil and gas at December 31, 2001, necessitated a pre-tax domestic full cost ceiling write-down of oil and gas properties of $98.9 million, or $63.5 million after-tax. Additionally, in the third quarter of 1998, we took a non-cash write-down of domestic oil and gas properties as prices for both oil and gas at September 30, 1998, necessitated a pre-tax domestic full-cost ceiling write-down in 1998 of $77.2 million, or $50.9 million after-tax. Also in the third quarter of 1998 we impaired our total investment in Russia of

$10.8 million and impaired our capitalized unproved properties costs in Venezuela of $2.8 million. The impairment of the unproved properties costs in these two countries resulted in a separate 1998 non-cash pre-tax charge to earnings of $13.6 million, or $9.0 million after-tax. The combination of the non-cash full cost domestic ceiling write-down and the non-cash foreign impairment charges in 1998 resulted in a combined non-cash charge to earnings of $90.8 million pre-tax, or $59.9 million after-tax.

(b) In December 2000, we called for redemption of all of our Convertible Notes 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 approximately $15.0 million remaining 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.

(c) We adopted SFAS No. 133 effective January 1, 2001. Accordingly, we marked our open derivative contracts at December 31, 2000 to fair value at that date resulting in a one-time net of taxes charge of $0.4 million which is recorded as a cumulative effect of change in accounting principle.

(d) EBITDA represents income before interest expense, income tax, and depreciation, depletion and amortization (including the write-down of oil and gas properties). We have reported EBITDA because we believe EBITDA is a measure commonly reported and widely used by investors as an indicator of a company's operating performance. We believe EBITDA assists such investors in comparing a company's performance on a consistent basis without regard to depreciation, depletion and amortization, which can vary significantly depending upon accounting methods or nonoperating factors such as historical cost. EBITDA is not a calculation based on GAAP and should not be considered an alternative to net income in measuring our performance or used as an exclusive measure of cash flow because it does not consider the impact of working capital growth, capital expenditures, debt principal reductions and other sources and uses of cash which are disclosed in our Consolidated Statements of Cash Flows. Investors should carefully consider the specific items included in our computation of EBITDA. While EBITDA has been disclosed herein to permit a more complete comparative analysis of our operating performance relative to other companies, investors should be cautioned that EBITDA as reported by us may not be comparable in all instances to EBITDA as reported by other companies. EBITDA amounts may not be fully available for management's discretionary use, due to certain requirements to conserve funds for capital expenditures, debt service and other commitments.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

You should read the following discussion and analysis in conjunction with our financial information and our consolidated financial statements and notes thereto included or incorporated by reference in this prospectus supplement. The following information contains forward-looking statements. For a discussion of limitations inherent in forward-looking statements, see "Forward-Looking Information" in the accompanying prospectus on page 3.

GENERAL

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

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.

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, our management evaluates, among other factors, 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 income.

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 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 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 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.

In addition, any unsuccessful exploratory well costs in countries in which there are no proved reserves are charged to expense as incurred. During the second quarter of 1999, we charged to income as additional depreciation, depletion, and amortization costs our portion of drilling costs associated with an unsuccessful exploratory well drilled by another operator in New Zealand. This charge was $290,000.

Because of the delineation of our 1999 Rimu discovery with two successful delineation wells drilled in 2000, proved reserves were recognized in New Zealand as of December 31, 2000.

Given the volatility of oil and gas prices, our estimates of discounted future net cash flows from proved oil and gas reserves are subject to change. If oil and gas prices decline significantly, even if only for a short period, it is possible that additional write-downs of oil and gas properties could occur in the future.

Price-Risk Management Activities. In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." The statement 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. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows the gains and losses on derivatives to offset related results on the hedged item in the income statements and requires that a company must 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 policy to use derivative instruments, mainly the buying of protection price floors, to protect against price declines in oil and gas prices. We elected not to designate our price floors for special hedge accounting treatment under SFAS No. 133, as amended. However, we have elected to use mark-to-market accounting treatment for our derivative contracts. 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 2001 we recognized net gains of $1,173,094 relating to our derivative activities, with $16,784 in unrealized losses at year end 2001. This activity is recorded in Price-risk management and other, net on the accompanying statements of income.

At December 31, 2001, we had open price floor contracts covering notional volumes of 2.0 million MMBtu of natural gas. These natural gas price floor contracts relate to the NYMEX contract months of February and March 2002 at an average price of $2.33 per MMBtu. The fair value of our open price floor contracts at December 31, 2001, totaled $296,000 and is included in Other current assets on the accompanying balance sheet.

PROVED OIL AND GAS RESERVES. At year end 2001, our total proved reserves were 645.8 Bcfe with a PV-10 Value of $603.0 million. In 2001, our proved natural gas reserves decreased 93.7 Bcf, or 22%, while our proved oil reserves increased 18.3 MMBbl, or 52%, for a total equivalent increase of 16.4 Bcfe, or 3%. From 1999 to 2000, our proved natural gas reserves increased by 88.7 Bcf, or 27%, while our proved oil reserves increased by 14.3 MMBbl, or 69%, for a total equivalent increase of 174.6 Bcfe, or 38%. We added reserves from 2000 to 2001 through both our drilling activity and through purchases of minerals in place. Through drilling we added 105.8 Bcfe (17.4 Bcfe of which came from New Zealand) of proved reserves in 2001, 184.7 Bcfe (122.5 Bcfe of which came from New Zealand) in 2000, and 64.9 Bcfe in 1999. Through acquisitions we added 54.6 Bcfe of proved reserves in 2001, 39.7 Bcfe in 2000, and 20.1 Bcfe in 1999. At year end 2001, 50% of our total proved reserves were proved developed, compared with 45% at year end 2000 and 49% at year end 1999.

While our total proved reserves quantities increased by 3% during 2001, the PV-10 Value of those reserves decreased 74%, primarily due to significantly lower prices at year end 2001 than at year end 2000. Between year end 2000 and year end 2001, there was a 75% decrease in natural gas prices and a 25% decrease in oil prices. Gas prices were $2.51 per Mcf at year end 2001, compared to $9.86 per Mcf at year end 2000. Oil prices were $18.45 per Bbl at year end 2001, compared to $24.62 a year earlier. These decreases in prices resulted in 47.1 Bcfe of the downward reserve revisions. 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. 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. Had year end reserves been calculated using the average 2001 prices we received, $22.64 for oil and $4.23 for gas, the PV-10 Value would have been approximately $947.8 million compared to the $603.0 million reported using year end prices.

RECENT EVENTS

TAWN ACQUISITION. Through our subsidiary, Swift Energy New Zealand Limited, we acquired Southern Petroleum Exploration Limited ("Southern NZ") from an affiliate of Shell New Zealand in January 2002 for approximately $54.4 million. Through Southern NZ we now own interests in four onshore producing oil and gas fields, extensive associated hydrocarbon-processing facilities and pipelines complementing our existing fields by providing us with access to export terminals and markets and additional excess processing capacity for both oil and natural gas. As of December 31, 2001, the reserves associated with this acquisition were estimated to be approximately 62.1 Bcfe, all of which were proved developed. This acquisition was accounted for using the purchase method of accounting. Upon the closing of this acquisition, our credit facility was increased to $300.0 million, and the borrowing base became $275.0 million.

In conjunction with the TAWN acquisition, we granted Shell New Zealand a short-term option to acquire an undivided 25% interest in our permit 38719, which includes our Rimu and Kauri areas, as well as a 25% interest in our Rimu Production Station. We do not know if Shell New Zealand will exercise this option. Any exercise of the option would be subject to numerous notifications, governmental approvals and consents. If Shell New Zealand does not exercise its option, we intend to pursue discussions with several other companies that have expressed interest in acquiring up to a 25% interest in the permit.

ANTRIM ACQUISITION. We purchased through our subsidiary, Swift Energy New Zealand Limited, all of the New Zealand assets owned by Antrim Oil and Gas Limited for 220,000 shares of Swift Energy Company common stock and an effective date adjustment of approximately $530,000. Antrim owned a 5% interest in permit 38719 and a 7.5% interest in permit 38716. As of December 31, 2001, the reserves associated with this acquisition were estimated to be approximately 5.7 Bcfe. This transaction closed in March 2002.

RUSSIA. On March 28, 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 Russian joint stock company, which owned and operated this field. This will result in a $7.5 million non-recurring, pre-tax gain in the first quarter of 2002.

RESULTS OF OPERATIONS

REVENUES. Our revenues in 2001 decreased by 4% compared to revenues in 2000 due primarily to decreases in oil prices.

Oil and gas sales revenues in 2001 decreased by 4%, or $8.0 million, from the level of those revenues for 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 $17.1 million of increases coming from the 583,000 Bbl increase in oil sales volumes, partially offset by a decrease of $4.5 million from the 1.1 Bcf decrease in gas sales volumes.

Revenues in 2000 increased by 73% compared to 1999 revenues. In 2000, oil and gas sales revenues increased by 74%, or $80.2 million, over those revenues in 1999. In 2000, net sales volumes decreased by 1%, or 0.5 Bcfe, compared to net sales volumes in 1999. Average oil prices received went from $16.75 per Bbl in 1999 to $29.35 per Bbl in 2000, and average gas prices received increased from $2.40 per Mcf in 1999 to $4.24 per Mcf in 2000.

In 2000, our $80.2 million increase in oil and gas sales resulted from:

- Price variances that had an $81.7 million favorable impact on sales, of which $31.1 million was attributable to the 75% increase in average oil prices received and $50.6 million was attributable to the 77% increase in average gas prices received; and

- Volume variances that had a $1.5 million unfavorable impact on sales, with $1.6 million of decreases coming from the 93,000 Bbl decrease in oil sales volumes, partially offset by an increase of $0.1 million from the 40,000 Mcf increase in gas sales volumes.

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

	NET SALES VOLUME			AVERAGE SALES PRICE	
	OIL (MBBL)	GAS (BCF)	COMBINED (BCFE)	OIL (PER BBL)	GAS (PER MCF
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
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
1999:					
First Qtr.	728	7.2	11.6	$10.87	$1.82
Second Qtr.	644	6.7	10.6	15.25	2.05
Third Qtr.	612	6.9	10.5	18.46	2.84
Fourth Qtr.	581	6.7	10.2	23.99	2.91
	2,565	27.5	42.9	$16.75	$2.40

Revenues from our oil and gas sales comprised 99% of total revenues for both 2001 and 2000 and 98% of total revenues for 1999. Natural gas production made up 59% of our production volumes in 2001, 65% in 2000, and 64% in 1999.

COSTS AND EXPENSES. Our general and administrative expenses, net in 2001 increased $2.6 million, or 47%, from the level of such expenses in 2000, while 2000 general and administrative expenses increased $1.1 million, or 24%, over 1999 levels. These increases reflect the increase in our corporate activities along with a reduction in reimbursement from partnerships we manage as these continue undergoing planned liquidation as voted upon by their limited partners. Our general and administrative expenses per Mcfe produced increased to $0.18 per Mcfe in 2001 from $0.13 per Mcfe in 2000 and $0.10 per Mcfe in 1999. The portion of supervision fees netted from general and administrative expenses was $3.1 million for 2001, $3.4 million for 2000, and $3.2 million for 1999.

Depreciation, depletion, and amortization of our assets, or DD&A, increased $11.7 million, or 25%, in 2001 from 2000, while 2000 DD&A increased $5.4 million, or 13%, from 1999 levels. In 2001, the increase was primarily due to additional dollars spent to add to our reserves and increased associated service costs

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in an environment where demand for such services had increased compared to 2000, along with a 6% increase in production. In 2000, the increase was primarily due to the additional dollars spent to add to our reserves and associated costs in 2000 over 1999. Our DD&A rate per Mcfe of production was $1.33 in 2001, $1.13 in 2000, and $0.99 in 1999, reflecting variations in per unit cost of reserves additions.

Our production costs in 2001 increased $7.5 million, or 26%, over such expenses in 2000, while those expenses in 2000 increased $9.6 million, or 49%, over 1999 costs. Our production costs per Mcfe produced were $0.82 in 2001, $0.69 in 2000, and $0.46 in 1999. The portion of supervision fees netted from production costs was $3.1 million for 2001, $3.4 million for 2000, and $3.2 million for 1999. 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 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 such services has increased from the prior year.

While our production costs increased 49% in 2000, our oil and gas sales increased 74%. That increase in oil and gas sales had a direct impact on the increase in production costs, as severance taxes have a direct correlation to sales and were $4.9 million higher in 2000. Also, the increase in commodity prices brought increased demand and competition for field services that resulted in an increase in the cost of those services. Remedial well work and workover costs increased $1.2 million over 1999 levels. In the Masters Creek area, salt-water disposal charges, which increased $0.4 million over 1999 charges, increased as the volume of water associated with that production increased. Also in the Masters Creek area, production chemical costs increased $0.6 million as we began our scale inhibitor program in that area.

Interest expense on our Senior Notes issued in July 1999, including amortization of debt issuance costs, totaled $13.1 million in both 2001 and 2000 and $5.3 million in 1999. Interest expense on our Convertible Notes due 2006, including amortization of debt issuance costs, totaled $7.4 million in 2000 and $7.5 million in 1999. Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $5.8 million in 2001, $0.7 million in 2000 and $6.1 million in 1999. The total interest expense in 2001 was $18.9 million, of which $6.3 million was capitalized. The 2000 total interest expense was $21.2 million, of which $5.2 million was capitalized. The 1999 total interest expense was $18.9 million, of which $4.5 million was capitalized. We capitalize that portion of interest related to our exploration, partnership, and foreign business development activities. 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. The increase in interest expense in 2000 was attributed to the replacement of our bank borrowings in August 1999 with the Senior Notes that carry a higher interest rate.

In the fourth quarter of 2001, we took 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 expensed $2.1 million of non-recurring charges in the fourth quarter of 2001 for certain delinquent accounts receivable, the majority of which was 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 our Consolidated Statement of Income.

In the fourth quarter of 2000, we recorded a $0.6 million non-recurring loss on the early extinguishment of debt (net of taxes), as discussed in Note 4 to the Consolidated 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 non-recurring item.

NET INCOME (LOSS). Our loss before extraordinary item and change in accounting principle in 2001 of $(22.0) million was 137% lower and Basic loss per share ("Basic EPS") before extraordinary item and change in accounting principle of $(0.89) was 132% lower than our 2000 net income of $59.8 million and Basic EPS of $2.82. These decreases reflected the effect of $101.0 million in non-recurring charges in 2001 as described above. The lower percentage decrease in Basic EPS reflects a 16% increase in weighted average shares outstanding in 2001, primarily due to the conversion of our Convertible Notes into 3.2 million shares of common stock in December 2000.

Our net loss for 2001 was $(22.3) million with a loss per share of $(0.90) per diluted share. Our net income for 2001, excluding non-recurring charges of $101.0 million as described above, totaled $42.5 million with EPS of $1.67 per diluted share. These amounts are lower than our 2000 net income of $59.8 million and EPS of $2.53 per diluted share, primarily due to significantly lower oil prices and overall increased costs.

Our income before extraordinary item in 2000 of $59.8 million was 210% higher and Basic EPS before extraordinary item of $2.82 was 164% higher than our 1999 net income of $19.3 million and Basic EPS of $1.07. These increases reflected the effect of the 75% increase in average oil prices received and 77% increase in average gas prices received. Oil and gas prices rose each quarter and resulted in quarterly sequential increases in earnings. The lower percentage increase in Basic EPS reflects an 18% increase in weighted average shares outstanding in 2000, primarily due to our third-quarter 1999 public sale of 4.6 million shares of common stock.

RELATED-PARTY TRANSACTIONS

We are the operator of a number of properties owned by our affiliated limited partnerships and joint ventures and, accordingly, charge these entities and third-party joint interest owners operating fees. The operating fees charged to the partnerships in 2001, 2000, and 1999 totaled approximately $925,000, $1,775,000, and $1,970,000, respectively. We are also reimbursed for direct, administrative, and overhead costs incurred in conducting the business of the limited partnerships, which totaled approximately $3,140,000, $4,465,000, and $4,000,000 in 2001, 2000, and 1999, 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 $2,360,000, $1,220,000, and $850,000 in 2001, 2000, and 1999, respectively.

CONTRACTUAL COMMITMENTS AND OBLIGATIONS

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

	2002	2003	2004	2005	THE
Non-cancelable operating lease commitments......................	$1,393,095	$1,480,092	$1,492,268	$ 248,711	$
Senior Subordinated Notes due August 2009............................	--	--	--	--	125
Credit Facility which expires in October 2005(1)..................	--	--	--	134,000,000	
	$1,393,095	$1,480,092	$1,492,268	$134,248,711	$125

(1) The repayment of the credit facility is based upon the balance at December 31, 2001. The amount borrowed under this facility has increased from 2001 year end levels. This amount excludes $0.8 million of a standby letter of credit issued under this facility.

LIQUIDITY AND CAPITAL RESOURCES

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

NET CASH PROVIDED BY OPERATING ACTIVITIES. In 2001, net cash provided by our operating activities increased by 9% to $139.9 million, as compared to $128.2 million in 2000 and $73.6 million in 1999. The 2001 increase of $11.7 million was primarily due to reductions 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. The 2000 increase of $54.6 million was primarily due to $80.2 million of additional oil and gas sales, partially offset by $12.2 million of increases in oil and gas production costs, general and administrative expenses, and interest expense.

EXISTING CREDIT FACILITIES. At December 31, 2001, we had $134.0 million in outstanding borrowings under our credit facility. Our credit facility at year end 2001 consisted of a $250.0 million revolving line of credit with a $200.0 million borrowing base. The borrowing base is redetermined at least every six months. 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, 2000, we had $10.6 million in outstanding borrowings under this facility.

Subsequent to December 31, 2001, upon the closing of the New Zealand TAWN acquisition, the credit facility was increased to $300.0 million and the borrowing base became $275.0 million. Our bank facility is described in more detail in "Description of Existing Indebtedness."

WORKING CAPITAL. Our working capital further declined from a deficit of $22.5 million at December 31, 2000, to a deficit of $36.5 million at December 31, 2001. The decrease was primarily due to reductions in oil and gas sales receivables, as oil and gas prices were lower at year end 2001, and an increase in payables to partnerships related to December 2001 oil and gas property sales.

CAPITAL EXPENDITURES IN 2001. Our capital expenditures of approximately $275.1 million included:

Domestic activities of $224.3 million as follows:

- $120.6 million, or 44%, for developmental drilling;

- $40.5 million, or 15%, for producing properties 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%, for exploratory drilling;

- $25.3 million, or 9%, for domestic prospect costs, principally leasehold, seismic, and geological costs;

- $1.1 million, or less than 1%, for fixed assets;

- $0.3 million for field compression facilities; and

- $0.1 million for gas processing plants in the Brookeland and Masters Creek areas.

New Zealand activities of $50.8 million as follows:

- $19.0 million, or 7%, for developmental drilling to further delineate the Rimu and Kauri areas;

- $17.9 million, or 7%, for the Rimu Production Station;

- $7.2 million, or 3%, for exploratory drilling in the Rimu and Kauri areas;

- $5.5 million, or 2%, for prospect costs, principally seismic and geological costs;

- $0.8 million, or less than 1%, for producing properties 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 successes. 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 unsuccessful and one was temporarily abandoned. Of our $95.9 million of unproved property costs, $72.3 million relates to our inventory of developmental and exploratory acreage to sustain drilling activity for future growth, while the remaining $23.6 million pertains to the Rimu Production Station which will be reclassified to proved properties once it comes on-line near the end of the first quarter of 2002.

CAPITAL EXPENDITURES FOR 2002. We estimate we will spend approximately $132.5 million during 2002. Approximately $39.8 million of the 2002 budget is allocated to domestic drilling, primarily in the Lake Washington area. In New Zealand, approximately $11.2 million of the 2002 budget is allocated to drilling, with another $8.7 million expected to be spent primarily for production facilities. In 2002, we anticipate drilling 20 development wells and 2 exploratory wells domestically, along with six development wells and one exploratory well in New Zealand. Approximately $54.6 million is targeted towards producing property acquisitions, the majority for the TAWN properties in New Zealand that closed in January 2002. Of the remainder, $13.5 million will be used primarily for domestic leasehold, seismic, and geological costs, and $4.7 million is budgeted for such costs in New Zealand. This $132.5 million budget also excludes any producing property acquisitions that may arise in this low price environment and also excludes any property sales. Although we expect our 2002 total production to increase by 10% to 20% over 2001 due to the focus of our budget in the Lake Washington area and in New Zealand, we expect production to decline in our other core areas as no new drilling is currently budgeted to offset their natural production decline.

We believe that the anticipated internally generated cash flows for 2002, together with bank borrowings under our credit facility, will be sufficient to finance the costs associated with our currently budgeted 2002 capital expenditures. Should other producing property acquisitions activity become attractive in the current environment, we intend to explore the use of debt and or equity offerings to fund such activity.

CAPITAL EXPENDITURES IN 2000 AND 1999. Our capital expenditures were approximately $173.3 million in 2000 and $78.1 million in 1999. During 1999, we used internally generated cash flows of $73.6 million to fund capital expenditures of $78.1 million. During 2000, we primarily used internally generated cash flows 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. Our capital expenditures in 2000 included:

Domestic activities of $157.9 million as follows:

- $90.3 million, or 52%, for developmental drilling;

- $33.4 million, or 19%, for producing properties acquisitions, approximately half of which was for the purchase of property interests from partnerships managed by us, with the other half purchased from a third party;

- $16.3 million, or 9%, for domestic prospect costs, principally leasehold, seismic, and geological costs;

- $15.5 million, or 9%, for exploratory drilling;

- $1.4 million, or 1%, for fixed assets;

- $0.8 million, or less than 1%, for gas processing plants in the Brookeland and Masters Creek areas; and

- $0.2 million for field compression facilities.

New Zealand activities of $15.4 million as follows:

- $7.6 million, or 4%, for developmental drilling to further delineate the Rimu area;

- $4.5 million, or 3%, for prospect costs, principally seismic and geological costs;

- $2.1 million, or 1%, for exploratory drilling;

- $1.1 million, or 1%, for the initial stages of production facilities; and

- $0.1 million, or less than 1%, for fixed assets, principally a field office and warehouse.

In 2000, we participated in drilling 61 development wells and nine exploratory wells, of which 54 development wells and five exploratory wells were successes. Two of the development wells were drilled in New Zealand to delineate the Rimu area, both of which were successful.

BUSINESS AND PROPERTIES

GENERAL

Swift Energy Company engages in developing, exploring, acquiring, and operating oil and gas properties, with a focus on onshore oil and natural gas reserves in Texas and Louisiana and onshore oil and natural gas reserves in New Zealand. At year end 2001, on a pro forma basis, we had estimated proved reserves of 713.6 Bcfe, concentrated 48% in Texas, 25% in Louisiana and 24% in New Zealand. Approximately 52% of these reserves are natural gas.

We currently focus our business in the following six core areas:

- AWP Olmos -- South Texas
- Masters Creek -- Central Louisiana
- Brookeland -- East Texas
- Lake Washington -- South Louisiana
- Rimu/Kauri -- New Zealand
- TAWN -- New Zealand

COMPETITIVE STRENGTHS AND BUSINESS STRATEGY

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

Successful track record

Our growth in reserves and production has resulted primarily from drilling activities in our core areas combined with producing property acquisitions. In 2001, we increased our proved reserves by 3%, which replaced 136% of our 2001 production. Our net cash provided by operations increased from $37.1 million in 1996 to $139.9 million in 2001. While 2001 production increased 6% in relation to 2000 production, we have increased our production from 19.4 Bcfe in 1996 to 44.8 Bcfe in 2001. We believe our experience in growing our reserves will be beneficial to us as we continue to pursue our business strategy.

Balanced Approach to Adding Reserves

Over the past five years, we have spent an average of 11% of our capital expenditure budget on exploration drilling, 51% on development activities, 19% on proved property acquisitions and 14% on lease acquisitions. 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. Over the five-year period ended December 31, 2001, we replaced 302% of our production at an average cost of $1.26 per Mcfe.

In this current environment of stronger oil prices in relation to gas prices, our 2002 capital expenditures are focused on developing and producing long-lived oil reserves in Lake Washington and in the Rimu/Kauri area. Our current focus on developing and acquiring long-lived reserves with an overall flatter production decline curve should strengthen our ongoing production profile and extend our average reserve life.

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 operator of 95% of our proved reserves at year end 2001. 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 Successful 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. We expect that the Rimu production station will be operational in April 2002, enabling 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.

During 2001 we produced and sold 84,261 Bbls on an extended production test basis at an average sales price of $21.64 per Bbl from our Rimu and Kauri wells. We have several exploration and delineation wells planned in the Rimu/Kauri area, as well as prospective areas in New Zealand outside of the Rimu/Kauri area that we will evaluate for drilling in the future.

In January 2002, we acquired the TAWN fields. From the closing of the TAWN acquisition on January 25, 2002 through March 25, 2002, these fields have generated an average daily net production of approximately 40 MMcfe. 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, 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 balanced capital budget, establishing leverage ratios that are appropriate given the volatility of the oil and gas markets and opportunistically accessing the capital markets. After giving effect to this offering, as of December 31, 2001, our long-term debt would have comprised approximately 41% of our total capitalization, or 45% after giving further effect to the proposed notes offering. As of February 28, 2002, after the TAWN acquisition in January 2002, and after giving effect to the Antrim acquisition in March 2002 and this offering, our long-term debt would have comprised approximately 48% of our total capitalization, which remains the same after giving further effect to the proposed notes offering. Additionally, after applying the net proceeds from this offering to reduce amounts outstanding under our credit facility, based on our February 28, 2002 balance, we expect to have approximately $81.3 million of available borrowing capacity, or $167.0 million after giving further effect to the proposed notes offering. By replacing indebtedness incurred under our revolving credit facility in connection with acquisition, development and exploitation activity with the net proceeds from this offering and the proposed notes offering, we will be implementing our strategy of matching long-lived assets with long-term debt and equity.

DOMESTIC CORE OPERATING AREAS

AWP Olmos Area

We began drilling and operating wells in the AWP Olmos area in 1988. Since that time, we have gained extensive expertise with the low-permeability, tight-sand formations typical of these fields. Our net proved reserves for this area of 207.5 Bcfe as of December 31, 2001 constituted 32% of our total reserves at that date. This field is characterized by long-lived reserves, with 74% of the reserves at year end 2001 comprised of natural gas.

Additionally, AWP Olmos area has yielded a steady production base, producing an average of approximately 35,700 Mcfe per day in 2001. We have maintained these rates by performing fracture extensions and installing coiled tubing velocity strings. During 2001, approximately 76% of our production from this field was natural gas. As of December 31, 2001, we owned interests in 496 wells and were the operator of 492 wells in this area producing gas from the Olmos Sand formation at depths from 10,000 to 11,500 feet. We own nearly a 100% working interest in almost all wells in this area in which we have an

interest. As of December 31, 2001, we owned drilling and production rights to approximately 28,562 net acres in this area in South Texas.

Geologically, this region is characterized by a blanket sand with an extensive fault system. In 2001, all 11 development wells we drilled in the AWP Olmos area were successful. As of December 31, 2001, we had 122 proved undeveloped locations in this area. Our planned 2002 capital expenditures in this area will focus on performing fracture extensions and installing coiled tubing velocity strings.

Masters Creek Area

We acquired our interest in this area in mid-1998 as part of a larger property acquisition. Located just east of the Texas-Louisiana border in the Louisiana parishes of Vernon and Rapides, this area contains our operated fields of Masters Creek and South Burr Ferry as well as other fields in which we have interests, but which are operated by others. As of December 31, 2001, we owned drilling and production rights to 194,212 gross acres, 149,400 net acres, and 141,000 fee mineral acres in this area.

The Masters Creek area contains horizontal wells producing both oil and gas from the Austin Chalk formation. In 2001, this area produced 15.3 Bcfe. In 2001, we drilled or participated in drilling nine development wells, all successful. As of December 31, 2001, we had 18 proved undeveloped drilling locations.

Brookeland Area

This area is located in southeast Texas in Jasper and Newton counties near the Texas-Louisiana border. This area also was a part of the 1998 property acquisition in which we acquired our interest in the Masters Creek area and contains horizontal wells producing both oil and gas from the Austin Chalk formation. In 2001, we drilled or participated in the drilling of 11 development wells, all successful. Our reserves in this area are approximately 60% oil and natural gas liquids.

As of December 31, 2001, we owned drilling and production rights to 127,703 gross acres, 79,874 net acres, and 15,000 fee mineral acres containing substantial proved undeveloped reserves. As of December 31, 2001, we had 17 proved undeveloped drilling locations in this field.

Lake Washington Field

We acquired interests in Lake Washington Field, located in Plaquemines Parish, Louisiana, effective March 1, 2001. Lake Washington Field produces oil from multiple Miocene sands ranging in depth from less than 2,000 feet to greater than 10,000 feet. This field is located on a salt dome and has produced over 300 million BOE since its inception. The area around the dome is heavily faulted, thereby creating a large number of potential traps. Since our acquisition of this field, we have mapped multiple zones covering all sides of the salt dome. We see both significant development opportunities and several distinct exploration plays on the property. Oil and gas from approximately 26 producing wells is gathered from four platforms located in water depths ranging from six feet to 11 feet, with drilling and workover operations performed with barge rigs. We have identified a number of under-exploited fault blocks in this area.

In 2001, we drilled four development wells and one exploratory well, and in 2002 we drilled two additional wells and a salt water disposal well, all of which were successful. As a result of our drilling and production activities, we have increased average production in the field net to our interest from approximately 652 BOE per day in March 2001, when we acquired the field, to approximately 1,236 BOE per day during February 2002. As of December 31, 2001, we owned drilling and production rights to 13,595 net acres. Our reserves in this field are approximately 95% oil and natural gas liquids. As of year end 2001, we had 29 proved undeveloped drilling locations in this field. Our planned 2002 capital expenditures in this field are approximately $25.0 million and include 20 development wells and two exploratory wells.

DOMESTIC EMERGING GROWTH AREAS

We are pursuing development and exploration activities in the following emerging growth areas, including areas where we drilled a number of wells in 2001. The timing and scope of our drilling in these areas depends upon changes in the relative prices of oil and gas and other market factors.

Frio (Garcia Ranch) Area in South Texas

This area, near the southern tip of Texas in Willacy and Kenedy counties, features the Frio formation at depths ranging from 10,000 to 16,000 feet. The traps are structure related and consist of faulted anticlines and three-way upthrown fault traps. Our prospects are defined by 3-D seismic surveys that were shot in the mid-1990s. We had two discoveries in the area in 2001, one in the Rome prospect in Willacy County at a depth of 16,388 feet, and the other in the

Siena prospect in Kenedy County at a depth of 16,300 feet. We have a 65% working interest in these prospects.

Wilcox Area in Texas Gulf Coast

This area is located along the Texas Gulf Coast in Goliad, Lavaca and Zapata counties. Our primary objectives are the Austin, Nita, Cameron, Brandon, Tina, Gracie, and Tyler Upper Wilcox sands. Traps in the Wilcox sand are both structural and stratigraphic and include upthrown fault traps as well as buried sand bars and sand channels, with formation depths ranging from 10,000 to 15,000 feet, as defined by both 2-D and 3-D seismic surveys.

Our 2001 exploration activity in this area had three discoveries in the Wilcox sands, 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 these two wells are 73% and 60%, respectively. The third well was in the Falcon Ridge prospect in Zapata County, Texas in which we have a 25% working interest.

Additionally, in Lavaca County we have another Wilcox prospect, the Pearl prospect. We currently have a 100% working interest in this prospect, but we have undertaken to market interests in the prospect to potential industry partners. The Pearl prospect has a projected depth for the test well of 14,500 feet. Additionally, we have other prospects in this area that we are considering for our future drilling activities.

Woodbine Area in East Texas

The Woodbine formation is located in southeast Texas in San Jacinto, Polk and Tyler counties. We drilled one well to the Woodbine formation during 2001 -- in the Lion prospect in San Jacinto County, Texas, to a depth of 15,800 feet. Although hydrocarbon-bearing intervals were found, the well was determined to be noncommercial.

Additionally, we have two other Woodbine prospects for future drilling: the Jaguar and Bobcat prospects, both located in Polk County, where we would serve as operator with approximately a 75% working interest.

Miocene Area in South Louisiana

We successfully drilled our first exploratory well in the Miocene sands in our new Lake Washington Area in Plaquemines Parish, Louisiana -- to a depth of 3,200 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. Current plans are to drill another exploratory well in the area during 2002.

Also in Plaquemines Parish, about 50 miles north of the Lake Washington Area, is the Delacroix area where we have been developing prospects for both shallow and deep horizons in the Miocene sands. The first well in this area, in the Grand Lake prospect, was drilled to a depth of 18,000 feet early in 2002 and was temporarily abandoned but may become a possible sidetrack well in the future.

NEW ZEALAND CORE OPERATING AREAS

Our activity in New Zealand began when we were issued two petroleum exploration permits in 1995 and 1996, which we combined in 1998 after surrendering a portion of this acreage. In 1999, we expanded this permit by adding 12,800 offshore acres. As of December 31, 2001 our permit 38719 included approximately 50,300 acres in the Taranaki Basin of New Zealand's North Island. We have a 95% working interest in this permit, and have fulfilled all current obligations under this permit. The initial five-year term of the permit ended on August 12, 2001. We have, however, extended our petroleum exploration permit an additional five years by relinquishing 50% of the acreage within the permit under the terms of the Crown Minerals Act of 1991. Specifically, we have chosen to relinquish acreage on the western and eastern portions of our permit that we feel is not prospective. The approximately 50,300 gross acres that we retain include all of the acreage that we believe is prospective, and include our Rimu and Kauri areas as well as our Tawa and Matai prospects.

As of December 31, 2001, our investment in New Zealand totaled approximately $84.4 million. Approximately $45.6 million of our investment costs have been included in the proved properties portion of our oil and gas properties and $38.8 million is included as unproved properties. After giving effect to our acquisitions in the first quarter of 2002, our total investment in New Zealand would have been $143.5 million, $54.4 million of which was used to acquire the TAWN assets, containing all proved producing reserves, and $4.7 million of which was used to acquire the Antrim assets.

At year end 2001, our proved reserves in the Rimu/Kauri area were estimated at 101.9 Bcfe, with 64% of such reserves classified as oil, natural gas liquids and condensates. We built production and processing facilities, which are initially designed to handle 3,500 Bbls of oil per day and 10,000 Mcf of processed natural gas per day. These facilities will allow us to commence sale of production from our Rimu discovery in April 2002. We recently entered into an agreement to sell to Genesis Power Limited approximately 38.0 Bcf of natural gas over a 10-year period. Natural gas deliveries from our Rimu discovery will begin under this contract once the Rimu production station is operational.

We expanded our operation in New Zealand in January 2002 with our purchase of Southern NZ Exploration, Ltd., from Shell New Zealand, through which we acquired interests in four fields and significant infrastructure assets. We have estimated the proved reserves associated with the TAWN acquisition at year end 2001 to be approximately 62.1 Bcfe, of which approximately 75% is natural gas. First quarter 2002 net daily production from the TAWN fields is estimated to be 1,071 Bbl of oil, 30 MMcf of natural gas, and 561 Bbl of natural gas liquids per day, or a total net daily production of approximately 40 MMcfe of natural gas per day.

Rimu Area

In 1996 we acquired our interest in permit 38719, which is located in the eastern onshore portion of the Taranaki Basin in New Zealand. In 1997, we acquired 2-D seismic data for two key areas in this permit. Based on analysis of this data, the first exploratory well, Rimu-A1, was drilled onshore in 1999. In late 1999, we successfully completed and production tested the Rimu-A1. Based upon additional 2-D seismic data acquired in March 2000, which better identified the extent of the Rimu structure, we drilled and tested two delineation wells, the Rimu-B1 and the Rimu-B2. In 2001 we have drilled and tested three more Rimu delineation wells, the Rimu-A2, Rimu-A3 and Rimu-B3. The Rimu-A3 was successful; the Rimu-A2 and Rimu-B3 were dry. Early in 2002, the Rimu-A2 was sidetracked and was successfully completed. The Rimu-B3 was also sidetracked in early 2002 and again was unsuccessful.

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 a 5,524-acre area for a primary term of 30 years. We plan to add up to three drilling pads in the permit area, for a total of five pads, with each able to handle multiple wells. Nine additional wells are currently planned within the mining permit, one gas injection well and eight development wells targeting the Upper Tariki and Lower Tariki sandstones and the Upper Rimu limestone.

Kauri Area

In 2000, we acquired approximately 45 miles of data from a number of 2-D transitional zone seismic lines tied to existing marine and land seismic grids to study the Kauri structure, which is to the south and southeast of our Rimu discovery. We based our well location on our interpretation of these data. We drilled our Kauri-A1 well to a total depth of 14,760 feet in the third quarter of 2001. We encountered significant hydrocarbon-bearing intervals in this well, and we intend to conduct extensive testing and analysis on these intervals in the future.

The initial hydrocarbon-bearing zone encountered in the Kauri-A1 well was found in a shallow section of the Miocene-Pliocene age sandstones, the Manutahi sand, beginning at a depth of 3,746 feet. Petrophysical analysis of logging data, along with laboratory analysis of sidewall cores, confirm an oil column of approximately 39 feet with excellent porosities and permeabilities. Based on electric log analysis and saturation measurements of the sidewall cores, an oil/water contact was found at 3,815 feet. Current geologic mapping indicates that this location is approximately 66 feet low to the top of the structure that covers approximately 1,000 acres of aerial extent in this fault block. We commenced drilling the Kauri-A2 development well in September 2001 in order to further evaluate this prospective interval. This well successfully tested the Manutahi Sands.

The second significant hydrocarbon-bearing interval encountered in the Kauri-A1 well was found in the Miocene age sandstones, the Kauri sand, beginning at a depth of 9,473 feet. This interval largely consists of multiple sections of sandstones and claystones that yielded oil and gas shows associated with drilling breaks and appears to be hydrocarbon bearing based on log analysis. Further petrophysical analysis of this data indicates a hydrocarbon-bearing sandstone interval of approximately 577 feet with good porosity. This same interval was also encountered, although not tested, in all of the previously drilled Rimu wells, with varying degrees of hydrocarbon shows. This interval in the Kauri-A1 well has greater sand development than in the Rimu wells, with mud log shows while drilling significantly better than in any of the previous wells drilled at Rimu.

The third and fourth hydrocarbon-bearing intervals encountered in this well were found in the Upper Tariki sand beginning at a depth of 11,126 feet and the Upper Rimu limestone beginning at a depth of 11,270 feet. Both of these intervals have also been present in all five wells drilled at Rimu, extending both of these intervals over a distance in excess of five miles. Based upon analysis of mud logs as well as the logging while drilling tools, the Upper Tariki appears to have a gross thickness of 30 feet and the Upper Rimu limestone appears to have a gross thickness of 33 feet.

The Kauri-B1 exploratory well was drilled approximately 1.75 miles to the southeast of the Kauri-A pad and targeted the Manutahi sands. This well was plugged and abandoned in late 2001.

TAWN Assets

The TAWN acquisition 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 Tariki Field and Ahuroa Field both produce from the Tariki formation, while the Waihapa Field and Ngaere Field produce from the Tikorangi formation. The four fields include 17 wells where the purchaser of gas has contracted to take minimum gas quantities and can call for higher production levels (which has occurred throughout 2002) to meet electrical demand in New Zealand.

Solution gas gathered from an oil facility, the Waihapa Production Station, or WPS, flows to the Tariki Ahuroa gas plant. The current processing capacity of the WPS facility is over 15,000 bbl of oil and 40 MMcf of natural gas per day. A 32 mile, eight 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, eight 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 Rimu/Kauri area will also have access to the Omata Tank Farm.

NEW ZEALAND EMERGING GROWTH AREAS

Tawa Prospect

The Tawa prospect is located on the southeast flank of Kapuni Field and its main targets are the Tikorangi limestone, the Upper Otaraoa sandstone and the Tariki sandstone. This is a combination structural and stratigraphic trap. This prospect was developed based upon our analysis of existing 3-D seismic data as well as new 2-D seismic surveys we acquired in 1997 and 2000.

Matai Prospect

The Matai prospect is located on the southeast flank of the Tawa prospect and its main target is the Moki sandstone. This prospect was identified based upon our analysis of new 2-D seismic data we acquired in 2000. We acquired additional seismic data in early 2002 to further evaluate this prospect.

Tuihu Prospect

In 2000, we entered into an agreement with Shell New Zealand whereby we earned a 20% participating interest in petroleum exploration permit 38718 containing approximately 57,400 acres. In January 2001, the operator temporarily abandoned the Tuihu #1 exploratory well pending further analysis. The permit now contains approximately 28,700 acres after a scheduled acreage surrender during December 2000. Additional analysis of the data from the well, as well as reinterpretation of the seismic data, is underway in order to determine further development plans.

Huinga Prospect

In 1998, we entered into agreements for a 7.5% working interest held by Antrim Oil and Gas Limited, a Canadian company, in permit 38716 operated by Marabella Enterprises Ltd. In turn, Antrim became 5% working interest owners in our permit 38719. An exploratory well was drilled on the 7.5% working interest permit and the well has been temporarily abandoned pending further evaluation. Operations to re-enter and sidetrack this well commenced in April 2002 to target a location to the west of the initial well. A five year extension was granted on this permit in 2001 upon the surrender of 50% of the acreage. As part of our March 2002 acquisition of Antrim's New Zealand assets, we acquired an additional 7.5% working interest in permit 38716, giving us a current 15.0% working interest in 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, 2001, 2000, and 1999. 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 us.

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, 2001, were estimated based upon prices in effect at year end. The weighted averages of such year end prices domestically were $2.68 per Mcf of natural gas and $18.51 per barrel of oil, compared to $11.25 and $25.50 at year end 2000 and $2.58 and $23.69 at year end 1999. The weighted averages of such year end 2001 prices for New Zealand were $1.18 per Mcf of natural gas and $18.25 per barrel of oil, compared to $0.71 and $22.30 in 2000. The weighted averages of such year end 2001 prices for all our reserves, both domestically and in New Zealand, were $2.51 per Mcf of natural gas and $18.45 per barrel of oil, compared to $9.86 and $24.62 in 2000. 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 proved reserves presented for all periods also exclude any reserves attributable to the volumetric production payment that was in effect in 2000 and 1999.

At year end 2001, 50% of our proved reserves were developed reserves. At year end 2000, 45% of our 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. While our total proved reserves quantities, on an equivalent Bcfe basis, at year end 2001 increased by 3% over reserves quantities a year earlier, the PV-10 Value of those reserves decreased 74% from the PV-10 Value at year end 2000. The decrease in prices resulted in 47.1 Bcfe of downward reserve revision, primarily attributed to the decrease in prices used at year end 2001. Our total proved reserves quantities at year end 2000 increased by 38% over reserves quantities a year earlier, while the PV-10 Value of those reserves increased 310% from the PV-10 Value at year end 1999. The PV-10 Value decrease in 2001 and the PV-10 increase in 2000 were heavily influenced by pricing decreases at year end 2001 as compared to year end 2000 and by pricing increases from year end 2000 as compared to year end 1999. 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, while oil prices increased 4% between the two dates, from $23.69 to $24.62 per barrel. Product prices for natural gas increased 16% during 1999, from $2.23 per Mcf at December 31, 1998, to $2.58 per Mcf at year end 1999, matched by a 111% increase in the price of oil between the two dates, from $11.23 to $23.69 per barrel.

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 SEC 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 of $454.6 million at year end 2001, $1,578.0 million at year end 2000 and $438.9 million at year end 1999 set forth in Supplemental Information to our Consolidated Financial Statements, which is calculated after provision for future income taxes.

	YEAR ENDED DECEMBER 31, 2001		
	TOTAL	DOMESTIC	NEW
ESTIMATED PROVED OIL AND GAS RESERVES			
Net natural gas reserves (Mcf):			
Proved developed	181,651,578	167,401,736	14
Proved undeveloped	143,260,547	121,087,764	22
Total	324,912,125	288,489,500	36
Net oil reserves (Bbl):			
Proved developed	23,759,574	20,393,142	3
Proved undeveloped	29,723,062	22,171,591	7
Total	53,482,636	42,564,733	10
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
Proved undeveloped	258,507,354	186,012,413	72
Total	$ 602,986,188	$ 492,107,794	$110

	YEAR ENDED DECEMBER 31, 2000		
	TOTAL	DOMESTIC	NEW

ESTIMATED PROVED OIL AND GAS RESERVES			
Net natural gas reserves (Mcf):			
Proved developed	215,169,833	215,169,833	
Proved undeveloped	203,444,143	148,130,666	55
Total	418,613,976	363,300,499	55
Net oil reserves (Bbl):			
Proved developed	10,980,196	10,980,196	
Proved undeveloped	24,153,400	12,962,513	11
Total	35,133,596	23,942,709	11
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
Total	$2,313,254,809	$2,176,958,773	$136

	YEAR ENDED DECEMBER 31, 1999		
	TOTAL	DOMESTIC	NEW
ESTIMATED PROVED OIL AND GAS RESERVES			
Net natural gas reserves (Mcf):			
Proved developed	174,046,096	174,046,096	
Proved undeveloped	155,913,654	155,913,654	
Total	329,959,750	329,959,750	
Net oil reserves (Bbl):			
Proved developed	8,437,299	8,437,299	
Proved undeveloped	12,368,964	12,368,964	
Total	20,806,263	20,806,263	
ESTIMATED PRESENT VALUE OF PROVED RESERVES			
Estimated present value of future net cash flows from proved reserves discounted at 10% per annum:			
Proved developed	$ 301,199,660	$ 301,199,660	$
Proved undeveloped	262,854,849	262,854,849	
Total	$ 564,054,509	$ 564,054,509	$

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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 estimate. 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.

A portion of our proved reserves has been accumulated through our interests in the limited partnerships for which we serve as general partner. The estimates of future net cash flows and their present values, based on period end prices, assume that some of the limited partnerships in which we own interests will achieve payout status in the future. At December 31, 2001, 32 of the limited partnerships managed by us had achieved payout status.

No other reports on our reserves have been filed with any federal agency.

OIL AND GAS WELLS

As we continue to sell properties on behalf of limited partnerships which have voted to liquidate, our total 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(
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
DECEMBER 31, 1999			
Gross	577	947	1,524
Net	105.5	449.2	554.7

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(1) Excludes 48 service wells in 2001, 25 service wells in 2000, and 33 service wells in 1999. Also excludes 5 wells in 2001 and 3 wells in 2000 in New Zealand, 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, 2001:

	DEVELOPED(1)		UNDEVELOPED(1)	
	GROSS	NET	GROSS	NET
Alabama	10,092	2,862	776	292
Arkansas	762	558	2,040	679
Kansas	--	--	4,520	1,909
Louisiana	135,148	92,489	138,532	89,804
Mississippi	730	176	--	--
Texas	232,258	145,162	96,817	64,807
Wyoming	522	120	84,212	74,997
All other states	--	--	5,928	981
Offshore Louisiana	4,609	276	25,000	1,536
Offshore Texas	14,400	1,601	450	23
Total -- Domestic	398,521	243,244	358,275	235,028
New Zealand(2)	24,901	22,411	135,459	79,552
Total	423,422	265,655	493,734	314,580

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(1) Fee mineral acreage acquired in the Masters Creek and Brookeland areas acquisition are not included in the above leasehold acreage table. We have 26,345 developed fee mineral acres and 114,655 undeveloped fee mineral acres in these two areas for a total of 141,000 fee mineral acres.

(2) Excludes 24,602 gross, and 23,805 net acres acquired in the TAWN acquisition that closed in January 2002, as well as 2,478 net acres acquired in the Antrim acquisition which closed in March 2002.

DRILLING ACTIVITIES

The following table sets forth the results of our drilling activities during the three years ended December 31, 2001:

		GROSS WELLS				NET WE	
YEAR	TYPE OF WELL	TOTAL	PRODUCING	DRY	TEMPORARILY ABANDONED	TOTAL	PRODUCING
2001	Exploratory -- Domestic	11	6	5	--	6.2	4.0
	Exploratory -- New Zealand	2	--	1	1	1.1	--
	Development -- Domestic	36	36	--	--	29.5	29.5
	Development -- New Zealand	4	2	2	--	3.6	1.8
2000	Exploratory -- Domestic	9	5	4	--	6.2	3.4
	Development -- Domestic	59	52	7	--	42.4	37.1

	Development -- New Zealand....................	2	2	--	--	1.8	1.8
1999	Exploratory -- Domestic....	3	1	2	--	1.5	0.3
	Exploratory -- New Zealand....................	2	1	--	1	1.0	0.9
	Development -- Domestic....	22	19	3	--	10.7	9.4

OPERATIONS

We generally seek to be operator in the wells in which we have 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 2001 ranged from $200 to $2,216 per well per month and totaled $6.2 million.

MARKETING OF PRODUCTION

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. Two oil or gas purchasers accounted for 10% or more each of our total revenues during the year ended December 31, 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. Our last sale to Enron was for November 2001 production. We currently have other purchasers for those volumes. For the year ended December 31, 2000, two purchasers accounted for approximately 37% 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 provides 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 Tapis posting, less the cost of storage, trucking, and transportation.

Our gas production from our TAWN fields, which we acquired and closed on in January 2002, is sold under a long-term contract with Contact Energy. Upon commissioning of the Rimu Production Station, our gas production from the Rimu field will be sold to Genesis Power Ltd. under a long-term contract.

Our natural gas liquids production from the TAWN fields is sold to RockGas under long-term contracts tied to New Zealand's domestic natural gas liquids market. Upon commissioning of the Rimu Production Station, our natural gas liquids from the Rimu Field also will be sold to RockGas.

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, 2001. "Net" production is production that is owned by us either 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,		
	2001	2000	1999
NET SALES VOLUME:			
Oil (Bbls)	3,055,374	2,472,014	2,564,924
Gas (Mcf)	26,458,958	27,524,621	27,484,759
Gas equivalents (Mcfe)	44,791,202	42,356,705	42,874,303
AVERAGE SALES PRICE:			
Oil (Per Bbl)	$ 22.64	$ 29.35	$ 16.75
Gas (Per Mcf)	$ 4.23	$ 4.24	$ 2.40
AVERAGE PRODUCTION COST (PER MCFE)	$ 0.82	$ 0.69	$ 0.46

Oil production for 2001 includes New Zealand production of 84,261 barrels, at an average price per barrel of $21.64. Natural gas production for 2000 and 1999 includes 405,130 and 728,235 Mcf, respectively, delivered under the volumetric production payment agreement pursuant to which we were obligated to deliver certain monthly quantities of natural gas (see Note 1 to the Consolidated Financial Statements). Under the volumetric production payment entered into in 1992, we delivered the last remaining commitment of gas in October 2000, when such agreement expired.

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. 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.

COMPETITION

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

PRICE RISK MANAGEMENT

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. In 1998, 1999 and 2000, price floors have been the primary financial instruments

that we have utilized to hedge our exposure to price risk for the three fiscal years ended December 31, 2000. During those periods, the costs and any benefits that we derived from price floors were recorded as a reduction or increase, as applicable, in oil and gas sales revenues. The costs to purchase put options were amortized over the option period.

During the fourth quarter of 1999, in addition to the price floor we had in place, we entered into participating collars to hedge oil production through June 2000. The participating collars were designated as hedges, and realized losses were recognized in oil and gas revenues in 2000 when the associated production occurred. During 1998, 1999 and 2000 we recognized net losses relating to our price floors and our collars of approximately $276,000, $561,000 and $1,114,000, respectively. This activity is recorded in oil and gas sales on the accompanying statements of income.

Effective January 1, 2001, we adopted SFAS No. 133. We did not elect to designate our contracts for special hedge accounting treatment and instead are using mark-to-market accounting treatment.

During 2001, we have continued our general practice of primarily using price floors to hedge our exposure to price risk. At December 31, 2001, we had open price floor contracts covering notional volumes of 2.0 million MMBtu of natural gas. Natural gas price floor contracts relate to the NYMEX contract months of February and March 2002, at an average price of $2.33 per MMBtu. The fair market value of our open price floor contracts at December 31, 2001 totaled $296,000 and is included under "Other Current Assets" on our December 31, 2001 balance sheet. During 2001 we recognized net gains of $1,173,094 relating to our derivative activities, with $16,784 of losses unrealized at year end 2001. This activity is recorded in "Price risk management and other, net" on our statements of income for 2001.

For recent information on our hedging activities, see "Summary -- Recent Developments."

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, 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. At year end 2001, we continued to serve as managing general partner of 71 of these various partnerships, of which 65 are production purchase partnerships that have been in existence from six to fifteen years and the remainder of which are drilling partnerships that have been in existence from three to five years.

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 properties or their interests in the partnerships and dissolve. During 2001, seven drilling partnerships and two production purchase partnerships were dissolved. We anticipate that the liquidation and dissolution of the additional 65 partnerships should be substantially completed by the end of 2002. The remaining six partnerships will continue to operate.

REGULATIONS

Environmental Regulations

The United States federal government and various state and local governments have adopted laws and regulations regarding the protection of human health and the environment. These laws and regulations may require the acquisition of a permit by operators before drilling commences, prohibit drilling activities on certain lands lying within wilderness areas, wetlands, or where pollution might cause serious harm, and impose substantial liabilities for pollution resulting from drilling operations, particularly with respect to

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operations in onshore and offshore waters or on submerged lands. Failure to comply with these laws and regulations may result in the imposition of administrative, civil, or criminal penalties or injunctive relief for failure to comply. These laws and regulations may increase the costs of drilling and operating wells. Because these laws and regulations change frequently, the costs of compliance with existing and future environmental laws and regulations cannot be predicted with certainty.

We currently own or lease, and have in the past owned or leased, numerous domestic properties that have been used for the exploration and production of oil and gas, some for many years. Although we have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been released on or under the properties owned or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under our control. These properties and the wastes disposed thereon or away from could be subject to stringent and costly investigatory or remedial requirements under applicable laws, some of which are strict liability laws without regard to fault or the legality of the original conduct, including the federal Comprehensive Environmental Response, Compensation and Liability Act, the federal Resources Conservation and Recovery Act, the federal Clean Water Act, the federal Oil Pollution Act, and analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), to perform natural resource mitigation or restoration practices, or to perform remedial plugging or closure operations to prevent future contamination.

Our oil and gas operations outside of the United States could also potentially be subject to similar foreign governmental controls and restrictions pertaining to protection of human health and the environment. Possible controls and restrictions may include the need to acquire permits, prohibition on drilling in certain environmentally sensitive areas, performance of clean-ups for any release of hydrocarbons or other wastes, and payment of penalties for any violations of applicable laws. We believe that compliance with existing requirements of such governmental bodies has not had a material adverse effect on our results of operations.

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

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

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

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

FEDERAL LEASES

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

LITIGATION

In the ordinary course of business, we have been party to various legal actions, which arise primarily from our activities as operator of oil and gas wells. In 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.

EMPLOYEES

At December 31, 2001, we employed 209 persons. In the January 2002 TAWN acquisition we acquired 22 employees in New Zealand, nine 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.

FACILITIES

We occupy approximately 91,000 square feet of office space at 16825 Northchase Drive, Houston, Texas, under a ten year lease expiring in 2005. The lease requires payments of approximately $116,000 per month. We have field offices in various locations, including New Zealand, from which our employees supervise local oil and gas operations.

MANAGEMENT

DIRECTORS AND EXECUTIVE OFFICERS

A. Earl Swift................................	Chairman of the Board
Terry E. Swift...............................	President, Chief Executive Officer, Director
Virgil N. Swift..............................	Vice Chairman of the Board
Joseph A. D'Amico............................	Executive Vice President and Chief Operating Offic
Bruce H. Vincent.............................	Executive Vice President -- Corporate Development Secretary
Alton D. Heckaman, Jr.	Senior Vice President -- Finance and Chief Financi Officer
James M. Kitterman...........................	Senior Vice President -- Operations
Victor R. Moran..............................	Senior Vice President -- Energy Marketing and Busi Development
David W. Wesson..............................	Controller
G. Robert Evans..............................	Director
Henry C. Montgomery..........................	Director
Clyde W. Smith, Jr.	Director
Harold J. Withrow............................	Director

A. Earl Swift, 68, is Chairman of the Board of Directors and has served in such capacity since Swift's founding in 1979. He previously served as President from 1979 to November 1997, at which time Terry E. Swift was appointed President. He also previously served as Chief Executive Officer from 1979 to May 2001, at which time Terry E. Swift was appointed Chief Executive Officer. For the 17 years prior to 1979, he was employed by affiliates of American Natural Resources Company. Mr. Swift is a registered professional engineer and holds a degree in petroleum engineering, Juris Doctor degree and a master's degree in business administration. He is the father of Terry E. Swift and the brother of Virgil N. Swift.

Terry E. Swift, 46, has served as a director since the 2000 annual shareholders meeting. He was appointed President in November 1997 and Chief Executive Officer in May 2001. He served as Executive Vice President from 1991 to 1997 and was Chief Operating Officer from 1991 to January 2000. He served as Senior Vice President -- Exploration and Joint Ventures from 1990 to 1991 and as Vice President -- Exploration and Joint Ventures from 1988 to 1990. Mr. Swift has a degree in chemical engineering and a master's degree in business administration. He is the son of A. Earl Swift and the nephew of Virgil N. Swift.

Virgil N. Swift, 73, has been a director since 1981, and currently serves as Vice Chairman of the Board. He acted as Executive Vice President -- Business Development between November 1991 and June 30, 2000. He previously served as Executive Vice President and Chief Operating Officer from 1982 to late 1991. Mr. Swift joined us in 1981 as Vice President -- Drilling and Production. For the preceding 28 years, he held various production, drilling and engineering positions with Gulf Oil Corporation and its subsidiaries, last serving as General Manager -- Drilling for Gulf Canada Resources, Inc. Mr. Swift is a registered professional engineer and holds a degree in petroleum engineering. He is the brother of A. Earl Swift and the uncle of Terry E. Swift.

Joseph A. D'Amico, 53, was appointed Executive Vice President in August 2000 and was appointed Chief Operating Officer in January 2000. He was Senior Vice President of Exploration and Development from February 1998 to January 2000. He served as Vice President of Exploration and Development from 1993 to 1998, Director of Exploration and Development from 1992 to 1993 and Funds Manager from 1988 to 1992. Mr. D'Amico holds Bachelor and Master of Science degrees in petroleum engineering and a master's degree in business administration.

Bruce H. Vincent, 54, has been Executive Vice President -- Corporate Development and Secretary since August 2000. Previously he served as Senior Vice President -- Funds Management since joining Swift in 1990. Mr. Vincent holds a degree in business administration and a master's degree in finance.

Alton D. Heckaman, Jr., 45, was appointed Senior Vice President -- Finance and Chief Financial Officer in August 2000. He had previously served as Vice President and Controller from May 1993 and Assistant Vice President -- Finance from March 1986 to May 1993. Mr. Heckaman joined Swift in 1982. He is a certified public accountant and holds a degree in accounting.

James M. Kitterman, 57, was appointed Senior Vice President -- Operations in May 1993. He had previously served as Vice President -- Operations since joining Swift in 1983. Mr. Kitterman holds a degree in petroleum engineering and a master's degree in business administration.

Victor R. Moran, 46, was appointed Senior Vice President -- Energy

Marketing and Business Development in August 2000. From 1995, he served as Vice President -- Natural Gas Marketing/Business Development. He had previously served as Director of Business Development since joining Swift in January 1992. Mr. Moran holds a degree in government and a Juris Doctor degree.

David W. Wesson, 43, was appointed Controller in January 2001. He previously served as Assistant Controller -- Reporting from April 1999 to January 2001, Manager, Reporting/Budget from October 1995 to April 1999 and Manager, Corporate Accounting/Budget from February 1990. He joined Swift as a Senior Accountant in 1988. Mr. Wesson is a certified public accountant and holds a degree in accounting.

G. Robert Evans, 70, has been a director since 1994. Effective January 1, 1998, Mr. Evans retired as Chairman of Material Sciences Corporation, having held that position since 1991. Material Sciences Corporation develops and commercializes continuously processed, coated materials technologies. He remains a director of Material Sciences Corporation. He also serves as a director of Consolidated Freightways, Inc., a trucking company.

Henry C. Montgomery, 66, has served as a director since 1987. Since 1980, Mr. Montgomery has been and continues to serve as the Chairman of the Board of Montgomery Financial Services Corporation, a management consulting and financial services firm. Mr. Montgomery specializes in services for companies in transition or that are financially troubled. The following describes some of those engagements. From January 2000 to early March 2001, Mr. Montgomery served as Executive Vice President, Financial and Administration, and Chief Finance Officer of Indus International, Inc., a public company engaged in enterprise asset management systems. For eight months in 1999 he served as interim Executive Vice President of Finance and Administration and currently serves on the board of directors of Spectrian Corporation, a public company engaged in making cellular base station power amplifiers. From November 1996 through July 1997, Mr. Montgomery served as Executive Vice President of SyQuest Technology, Inc., a public company engaged in the development, manufacture and sale of computer hard drives. On November 17, 1998, SyQuest filed a petition under Chapter 11 of the U.S. Bankruptcy Code. Mr. Montgomery served from March 1995 until mid-November 1996 as President and Chief Executive Officer of New Media Corporation, a privately held company engaged in developing, manufacturing and selling PCMCIA cards for the computer industry. On October 14, 1998, New Media Corporation filed a petition under Chapter 11 of the U.S. Bankruptcy Code. Mr. Montgomery currently also serves on the boards of directors of Consolidated Freightways Corporation, a trucking company, and Catalyst Semiconductor, Inc., a company that designs, develops and markets programmable integrated circuit products.

Clyde W. Smith, Jr., 53, has served as a director since 1984. Since January 2002, Mr. Smith has served as President of Ascentron, Inc., an electronics manufacturing services company that acquired the assets of D.W. Manufacturing, Inc. in January 2002. From May 1998 until January 2002, Mr. Smith served as General Manager of D.W. Manufacturing, Inc. d/b/a Millennium Technology Services, an Oregon based electronics manufacturer. From August 1997 to May 1998, when its assets were acquired by D.W. Manufacturing, Mr. Smith served as President of Millenium Technology, Inc., a debtor-in-possession under the U.S. Bankruptcy Code. He served as President of Somerset Properties, Inc., a real estate investment company, from 1985 to 1994 and as President of H&R Precision, Inc., a general contractor, from 1994 to August 1997. Mr. Smith is a certified public accountant. On May 7, 1997, Mr. Smith filed a petition under Chapter 7 of the U.S. Bankruptcy Code.

Harold J. Withrow, 74, has been a director since 1988. Mr. Withrow worked as an independent oil and gas consultant from 1988 until he retired at the end of 1995. From 1975 until 1988, Mr. Withrow served as Senior Vice President -- Gas Supply for Michigan Wisconsin Pipe Line Company and its successor, ANR Pipeline Company.

DESCRIPTION OF EXISTING INDEBTEDNESS

CREDIT FACILITY

Our $300.0 million credit facility with a nine bank syndicate, which is scheduled to mature on October 1, 2005, is secured by substantially all of our oil and gas properties. The amount available for borrowing is subject to a borrowing base determination that is re-calculated at least every six months. Our current borrowing base is $275.0 million. Our borrowing base will be reduced by 40% of the amount of the proposed notes offering upon its closing. Our proposed notes offering is expected to close in mid-April 2002, although we can provide no assurance in this regard. Without taking this reduction into account, the bank syndicate reconfirmed this borrowing base effective April 5, 2002. At December 31, 2001 and February 28, 2002, we had $134.0 million and $220.2 million in outstanding borrowings under our credit facility. After we apply the net proceeds of this offering to reduce our bank debt, based upon our outstanding indebtedness at February 28, 2002, we anticipate we would have approximately $193.7 million outstanding under our credit facility. This amount will be reduced to approximately $48.0 million after application of the net proceeds we expect from the proposed notes offering.

Under our current credit facility and depending on the level of outstanding debt, the interest rate is either the lead bank's base rate, 4.75% at December 31, 2001, or, at our option, LIBOR plus the applicable margin, which was 3.64% for our outstanding borrowings at December 31, 2001. The weighted average interest rate was 3.53% for our outstanding borrowings at February 28, 2002.

The terms of the revolving line of credit include, among other restrictions, a limitation on cash dividends, requirements as to maintenance of certain minimum financial ratios, including maintaining working capital and debt and equity ratios, and limitations on incurring other debt. Since inception, no cash dividends have been declared on our common stock. Our credit facility limits our repurchase of shares of common stock to $15.0 million from September 28, 2001. In addition, our credit facility contains certain covenants that limit, among other things, our ability to:

- incur debt;

- dispose of property and assets;

- enter into consolidation or merger transactions;

- enter into certain contracts or leases; and

- expand into other lines of business.

For all periods presented in this prospectus supplement, we were in compliance with the provisions of our credit facility. For a detailed description of this credit facility, see the credit agreement which is attached as Exhibit 10.16 of our Quarterly Report on Form 10-Q for the quarter ended September 30, 2001.

SENIOR SUBORDINATED NOTES DUE 2009

On August 4, 1999, we issued $125.0 million aggregate principal amount of 10.25% senior subordinated notes due August 1, 2009.

Payments of principal, interest and premium under the senior subordinated notes due 2009 will be subordinated to payments on our existing and future senior debt, including our credit facility. On or after August 1, 2004, we may redeem our senior subordinated notes due 2009 for cash at 105.125% of principal declining to 100% in 2007. In addition, before August 1, 2002, we may redeem up to 33.33% of our senior subordinated notes due 2009 with the proceeds of qualified offerings of our equity at 110.25% of their principal amount, together with accrued and unpaid interest. If certain changes in control occur, or if our common stock ceases trading on a national exchange, each holder of the senior subordinated notes due 2009 will have the right to require us to repurchase their senior subordinated notes due 2009 at 101% of the note's principal amount, plus accrued and unpaid interest to the date of repurchase.

For a detailed description of the senior subordinated notes due 2009 and their provisions, see the indenture and the supplement filed as an exhibit to the senior subordinated notes registration statement on July 9, 1999 and to our Current Report on Form 8-K filed with the SEC on August 4, 1999, respectively.

UNDERWRITING

Under the terms and subject to the conditions contained in an underwriting agreement dated April 9, 2002, we have agreed to sell to Credit Suisse First Boston Corporation ("CSFB") all of the shares of common stock in this offering.

The underwriting agreement provides that CSFB is obligated to purchase all of the shares of common stock in this offering if any are purchased, other than those shares covered by the over-allotment option described below.

We have granted to CSFB a 30-day option to purchase up to 225,000 additional shares at the initial public offering price less the underwriting discounts and commissions. The option may be exercised only to cover any over-allotments of common stock.

CSFB proposes to offer the shares of common stock initially at the public offering price on the cover page of this prospectus supplement and to selling group members at that price less a selling concession of $0.30 per share. CSFB and selling group members may allow a discount of $0.10 per share on sales to other broker/dealers. After the initial public offering, CSFB may change the public offering price and concession and discount to broker/dealers.

The following table summarizes the compensation and estimated expenses we will pay.

	PER SHARE		TOTAL	
	WITHOUT OVER-ALLOTMENT	WITH OVER-ALLOTMENT	WITHOUT OVER-ALLOTMENT	WITH OVER ALLOTM
Underwriting discounts and commission payable by				

us...	$0.50	$0.50	$750,000	$862,5
Expenses payable by us.............................	$0.08	$0.08	$125,000	$135,0

We have agreed that we will not offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, or file with the SEC a registration statement under the Securities Act of 1933 (the "Securities Act") relating to, any shares of our common stock or securities convertible into or exchangeable or exercisable for any shares of our common stock, or publicly disclose the intention to make any such offer, sale, pledge, disposition or filing, without the prior written consent of CSFB for a period of 90 days after the date of this prospectus supplement, except issuances pursuant to the exercise of outstanding options, grants of employee stock options pursuant to the terms of existing employee benefit plans, and issuances pursuant to the exercise of such options.

Our executive officers and directors have agreed that they will not offer, sell, contract to sell, pledge or otherwise dispose of, directly or indirectly, any shares of our common stock or securities convertible into or exchangeable or exercisable for any shares of our common stock, enter into a transaction that would have the same effect, or enter into any swap, hedge or other arrangement that transfers, in whole or in part, any of the economic consequences of ownership of our common stock, whether any of these transactions are to be settled by delivery of our common stock or other securities, in cash or otherwise, or publicly disclose the intention to make any offer, sale, pledge or disposition, or to enter into any transaction, swap, hedge or other arrangement, without, in each case, the prior written consent of CSFB for a period of 90 days after the date of this prospectus supplement.

We have agreed to indemnify CSFB against liabilities under the Securities Act or contribute to payments that CSFB may be required to make in that respect.

In connection with the offering CSFB may engage in stabilizing transactions, over-allotment transactions, syndicate covering transactions and penalty bids in accordance with Regulation M under the Securities Exchange Act of 1934.

- Stabilizing transactions permit bids to purchase the underlying security so long as the stabilizing bids do not exceed a specified maximum.

- Over-allotment involves sales by CSFB of shares in excess of the number of shares CSFB is obligated to purchase, which creates a syndicate short position. The short position may be either a covered short position or a naked short position. In a covered short position, the number of shares over-allotted by CSFB is not greater than the number of shares it may purchase in the over-allotment option. In a naked short position, the number of shares involved is greater than the number of shares in the over-allotment option. CSFB may close out any covered short position by either exercising its over-allotment option and/or purchasing shares in the open market.

- Syndicate covering transactions involve purchases of common stock in the open market after the distribution has been completed in order to cover syndicate short positions. In determining the source of shares to close out the short position, CSFB will consider, among other things, the price of shares available for purchase in the open market as compared to the price at which it may purchase shares through the over-allotment option. If CSFB sells more shares than could be covered by the over-allotment option, a naked short position, the position can only be closed out by buying shares in the open market. A naked short position is more likely to be created if CSFB is concerned that there could be downward pressure on the price of the shares in the open market after pricing that could adversely affect investors who purchase in the offering.

- Penalty bids permit CSFB to reclaim a selling concession from a syndicate member when the common stock originally sold by the syndicate member is purchased in a stabilizing transaction or a syndicate covering transaction to cover syndicate short positions.

These stabilizing transactions, syndicate covering transactions and penalty bids may have the effect of raising or maintaining the market price of our common stock or preventing or retarding a decline in the market price of our common stock. As a result, the price of our common stock may be higher than the price that might otherwise exist in the open market. These transactions, if commenced, may be discontinued at any time.

A prospectus in electronic format may be made available on the web sites maintained by CSFB, or selling group members, if any, participating in this offering. CSFB may agree to allocate a number of shares to itself and selling group members for sale to their online brokerage account holders. Internet distributions will be allocated by CSFB and selling group members that will make internet distributions on the same basis as other allocations.

In the ordinary course of their businesses, CSFB and its affiliates have engaged, and/or may in the future engage, in investment banking or commercial banking transactions with us and our affiliates. CSFB will not receive any benefit from this offering other than the underwriting discount to be provided by us. CSFB is the lead manager of our proposed notes offering.

NOTICE TO CANADIAN RESIDENTS

RESALE RESTRICTIONS

The distribution of the common stock in Canada is being made only on a private placement basis exempt from the requirement that we prepare and file a prospectus with the securities regulatory authorities in each province where trades of common stock are made. Any resale of the common stock in Canada must be made under applicable securities laws which will vary depending on the relevant jurisdiction, and which may require resales to be made under available statutory exemptions or under a discretionary exemption granted by the applicable Canadian securities regulatory authority. Purchasers are advised to seek legal advice prior to any resale of the common stock.

REPRESENTATIONS OF PURCHASERS

By purchasing common stock in Canada and accepting a purchase confirmation a purchaser is representing to us and the dealer from whom the purchase confirmation is received that

- the purchaser is entitled under applicable provincial securities laws to purchase the common stock without the benefit of a prospectus qualified under those securities laws;

- where required by law, that the purchaser is purchasing as principal and not as agent; and

- the purchaser has reviewed the text above under "Resale Restrictions."

RIGHTS OF ACTION -- ONTARIO PURCHASERS ONLY

Under Ontario securities legislation, a purchaser who purchases a security offered by this prospectus supplement during the period of distribution will have a statutory right of action for damages, or while still the owner of the shares, for rescission against us in the event that this prospectus supplement and/or the accompanying prospectus contains a misrepresentation. A purchaser will be deemed to have relied on the misrepresentation. The right of action for damages is exercisable not later than the earlier of 180 days from the date the purchaser first had knowledge of the facts giving rise to the cause of action and three years from the date on which payment is made for the shares. The right of action for rescission is exercisable not later than 180 days from the date on which payment is made for the shares. If a purchaser elects to exercise the right of action for rescission, the purchaser will have no right of action for damages against us. In no case will the amount recoverable in any action exceed the price at which the shares were offered to the purchaser and if the purchaser is shown to have purchased the securities with knowledge of the misrepresentation, we will have no liability. In the case of an action for damages, we will not be liable for all or any portion of the damages that are proven to not represent the depreciation in value of the shares as a result of the misrepresentation relied upon. These rights are in addition to, and without derogation from, any other rights or remedies available at law to an Ontario purchaser. The foregoing is a summary of the rights available to an Ontario purchaser. Ontario purchasers should refer to the complete text of the relevant statutory provisions.

ENFORCEMENT OF LEGAL RIGHTS

All of our directors and officers as well as the experts named herein may be located outside of Canada and, as a result, it may not be possible for Canadian purchasers to effect service of process within Canada upon us or those persons. All or a substantial portion of our assets and the assets of those persons may be located outside of Canada and, as a result, it may not be possible to satisfy a judgment against us or those persons in Canada or to enforce a judgment obtained in Canadian courts against us or those persons outside of Canada.

TAXATION AND ELIGIBILITY FOR INVESTMENT

Canadian purchasers of common stock should consult their own legal and tax advisors with respect to the tax consequences of an investment in the common stock in their particular circumstances and about the eligibility of the common stock for investment by the purchaser under relevant Canadian legislation.

LEGAL MATTERS

The validity of the offered common stock will be passed upon for us by Jenkens & Gilchrist, a Professional Corporation, Houston, Texas. Certain legal matters will be passed upon for the underwriters by Vinson & Elkins L.L.P., Houston, Texas.

EXPERTS

The audited financial statements included in this prospectus supplement have been audited by Arthur Andersen LLP, independent public accountants, as indicated in their report with respect thereto, and are included herein in reliance upon the authority of said firm as experts in accounting and auditing in giving said report.

Information set forth in this prospectus supplement regarding our estimated quantities of oil and gas reserves and the discounted present value of future net cash flows therefrom is based upon estimates of such reserves and present values prepared by H.J. Gruy & Associates, Inc., independent petroleum engineers. All such information has been so included herein in reliance upon the authority of such firm as experts in such matters.

OTHER MATTERS

On March 14, 2002, our independent public accountant, Arthur Andersen LLP, was indicted on federal obstruction of justice charges arising from the federal government's investigation of Enron Corp. Arthur Andersen has pled not guilty and indicated that it intends to contest the indictment. Given the uncertainty surrounding the indictment, it may become difficult for purchasers of the common stock to seek remedies against Arthur Andersen. The SEC has said that it will continue accepting financial statements audited by Arthur Andersen, and interim financial statements reviewed by it, so long as Arthur Andersen is able to make certain representations to its clients concerning audit quality controls, which representations have been made to us. Our Audit Committee has been monitoring these developments, and if necessary will take appropriate action regarding the auditing of our financial statements.

GLOSSARY OF TERMS

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

BBL means barrel or barrels of oil.

BCF means billion cubic feet of natural gas.

BCFE means billion cubic feet of natural gas equivalent (see Mcfe).

BOE means one revenue interests barrel of oil equivalent using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas.

BTU means British thermal unit, which is a heating equivalent measure for natural gas (see MMBtu).

DEVELOPMENT WELL means 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.

EXPLORATORY WELL means 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.

FAIR MARKET VALUE is defined as the maximum price that a willing buyer will pay and a willing seller will sell at a given point in time at which the buyer is under no compulsion to buy and the seller is not compelled to sell, both having reasonable knowledge of all the material circumstances.

GROSS ACRE means 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 means 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.

MCF means thousand cubic feet of natural gas.

MCFE means thousand cubic feet of natural gas equivalent, which is determined using the ratio of one barrel of oil, condensate or natural gas liquids to six Mcf of natural gas.

MMBOE means million barrels of oil equivalent (see BOE).

MMBTU means 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 prices per MMBtu, the same basis on which natural gas is contracted for sale.

MMCF means million cubic feet of natural gas.

MMCFE means million cubic feet of natural gas equivalent (see Mcfe).

NET ACRE means the sum of fractional ownership working interests 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 is deemed to exist when the sum of fractional ownership working interests 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 means natural gas liquid.

PRODUCING WELL means 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 RESERVES means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

PROVED UNDEVELOPED RESERVES means proved reserves that are expected to be recovered from new wells on undrilled acreage.

PROVED OIL AND GAS RESERVES means 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.

PV-10 VALUE means, in accordance with SEC guidelines, the estimated future net cash flow 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 services, future income tax expenses or depreciation, depletion and amortization.

PRODUCING PROPERTIES means properties (or interests in properties) producing oil and gas in commercial quantities. Producing Properties include associated well machinery and equipment, gathering systems, storage facilities or processing installations or other equipment and property associated with the production and field processing of oil or gas. Interests in Producing Properties may include Working Interests, production payments, Royalty Interests, Overriding Royalty Interest, Net Profits Interests and other non-operating interests. Producing Properties may include gas gathering lines or pipelines. The geographical limits of a Producing Property may be enlarged or contracted on the basis of subsequently acquired geological data to define the productive limits of a reservoir, or as a result of action by a regulatory agency employing such criteria as the regulatory agency may determine.

PROVED RESERVES means those quantities of crude oil, natural gas and natural gas liquids which, upon analysis of geologic and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. Proved Reserves are limited to those quantities of oil and gas which can be reasonably expected to be recoverable commercially at current prices and costs, under existing regulatory practices and with existing conventional equipment and operating methods.

RESERVE REPLACEMENT COST means, 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.

ROYALTY INTEREST means a fractional interest in the gross production, or the gross proceeds therefrom, of oil and gas and other minerals under a lease; free of any expenses of exploration, development, operation and maintenance.

SFAS means Statement of Financial Accounting Standards.

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

WORKING INTEREST means the operating interest under an oil, gas and mineral lease or other property interest covering a specific tract or tracts of land. The owner of a Working Interest has the right to explore for, drill and produce the oil, gas and other minerals covered by such lease or other property interest and the obligation to bear the costs of exploration, development, operation or maintenance applicable to that owner's interest.

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SWIFT ENERGY COMPANY AND SUBSIDIARIES

CONSOLIDATED FINANCIAL STATEMENTS

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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

Houston, Texas
February 18, 2002

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SWIFT ENERGY COMPANY AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

	DECEMBER 31,	
	2001	2000
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2,149,086	$ 1,986,932
Accounts receivable --		
Oil and gas sales	14,215,189	26,939,472
Associated limited partnerships and joint ventures	6,259,604	2,685,003
Joint interest owners	11,467,461	7,181,974
Other current assets	2,661,640	3,079,498
Total Current Assets	36,752,980	41,872,879
Property and Equipment:		
Oil and gas, using full cost accounting		
Proved properties being amortized	974,698,428	753,426,124
Unproved properties not being amortized	95,943,163	55,512,872

	1,070,641,591	808,938,996
Furniture, fixtures, and other equipment	8,706,414	8,873,266
	1,079,348,005	817,812,262
Less -- Accumulated depreciation, depletion, and amortization	(448,139,334)	(290,725,112)
	631,208,671	527,087,150
Other Assets:		
Deferred charges	3,723,182	3,426,972
	3,723,182	3,426,972
	$ 671,684,833	$ 572,387,001

LIABILITIES AND STOCKHOLDERS' EQUITY

Current Liabilities:		
Accounts payable and accrued liabilities	$ 38,884,380	$ 54,977,397
Payable to associated limited partnerships	26,573,490	1,291,787
Undistributed oil and gas revenues	7,787,465	8,055,587
Total Current Liabilities	73,245,335	64,324,771
Long-Term Debt	258,197,128	134,729,485
Deferred Income Taxes	27,589,650	41,178,590
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 and 35,000,000 shares authorized, 25,634,598 and 25,452,148 shares issued, and 24,795,564 and 24,608,344 shares outstanding, respectively	256,346	254,521
Additional paid-in capital	296,172,820	293,396,723
Treasury stock held, at cost, 839,034 and 843,804 shares, respectively	(12,032,791)	(12,101,199)
Retained earnings	28,256,345	50,604,110
	312,652,720	332,154,155
	$ 671,684,833	$ 572,387,001

See accompanying Notes to Consolidated Financial Statements.

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SWIFT ENERGY COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Revenues:			
Oil and gas sales	$181,184,635	$189,138,947	$108,898,696
Fees from limited partnerships and joint ventures	427,583	331,497	229,749
Interest income	49,281	1,339,386	833,204
Price risk management and other, net	2,145,991	815,116	709,358
	183,807,490	191,624,946	110,671,007
Costs and Expenses:			
General and administrative, net of reimbursement	8,186,654	5,585,487	4,497,400
Depreciation, depletion, and amortization	59,502,040	47,771,393	42,348,901
Oil and gas production	36,719,609	29,220,315	19,645,740
Interest expense, net	12,627,022	15,968,405	14,442,815
Other expenses	2,102,251	--	--
Write-down of oil and gas properties	98,862,247	--	--
	217,999,823	98,545,600	80,934,856
Income (Loss) Before Income Taxes, Extraordinary Item and Change in Accounting Principle	(34,192,333)	93,079,346	29,736,151
Provision (Benefit) for Income Taxes	(12,237,436)	33,265,480	10,449,577
Income (Loss) Before Extraordinary Item and Change in Accounting Principle	$(21,954,897)	$ 59,813,866	$ 19,286,574
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)	$(22,347,765)	$ 59,184,008	$ 19,286,574
Per Share Amounts --			
Basic: Income (Loss) Before Extraordinary Item and Change in Accounting Principle	$ (0.89)	$ 2.82	$ 1.07
Extraordinary Loss	--	(0.03)	--
Change in Accounting Principle	(0.01)	--	--
Net Income (Loss)	$ (0.90)	$ 2.79	$ 1.07
Diluted: Income (Loss) Before Extraordinary Item and Change in Accounting Principle	$ (0.89)	$ 2.53	$ 1.07
Extraordinary Loss	--	(0.02)	--
Change in Accounting Principle	(0.01)	--	--
Net Income (Loss)	$ (0.90)	$ 2.51	$ 1.07
Weighted Average Shares Outstanding	24,732,099	21,244,684	18,050,106

See accompanying Notes to Consolidated Financial Statements.

SWIFT ENERGY COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

	COMMON STOCK(1)	ADDITIONAL PAID-IN CAPITAL	TREASURY STOCK	RETAINED EARNINGS (DEFICIT)	TO
Balance, December 31, 1998...	$169,725	$148,901,270	$(11,841,884)	$(27,866,472)	$109,
Stock issued for benefit plans (90,738 shares)...........	224	(366,408)	978,956	--	
Stock options exercised (65,477 shares)...........	655	461,102	--	--	
Employee stock purchase plan (22,771 shares)...........	228	181,577	--	--	
Public stock offering (4,600,000 shares).........	46,000	41,915,310	--	--	41,
Purchase of 246,500 shares as treasury stock..........	--	--	(1,462,740)	--	(1,
Net income..................	--	--	--	19,286,574	19,
Balance, December 31, 1999...	$216,832	$191,092,851	$(12,325,668)	$ (8,579,898)	$170,
Stock issued for benefit plans (46,632 shares)...........	310	297,060	224,469	--	
Stock options exercised (543,450 shares)..........	5,434	4,316,446	--	--	4,
Employee stock purchase plan (29,889 shares)...........	299	297,414	--	--	
Subordinated notes conversion (3,164,644 shares).........	31,646	97,392,952	--	--	97,
Net income..................	--	--	--	59,184,008	59,
Balance, December 31, 2000...	$254,521	$293,396,723	$(12,101,199)	$ 50,604,110	$332,
Stock issued for benefit plans (11,945 shares)...........	72	354,973	68,408	--	
Stock options exercised (152,915 shares)..........	1,529	1,942,634	--	--	1,
Employee stock purchase plan (22,360 shares)...........	224	478,490	--	--	
Net loss....................	--	--	--	(22,347,765)	(22,
Balance, December 31, 2001...	$256,346	$296,172,820	$(12,032,791)	$ 28,256,345	$312,

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(1) $.01 par value

See accompanying Notes to Consolidated Financial Statements.

SWIFT ENERGY COMPANY AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Cash Flows from Operating Activities:			
Net income (loss)	$ (22,347,765)	$ 59,184,008	$ 19,286,574
Adjustments to reconcile net income (loss) to net cash provided by operating activities --			
Depreciation, depletion, and amortization	59,502,040	47,771,393	42,348,901
Write-down of oil and gas properties	98,862,247	--	--
Deferred income taxes	(12,555,618)	33,413,626	10,435,115
Deferred revenue amortization related to production payment	--	(587,629)	(1,056,284)
Other	509,973	1,075,848	628,614
Change in assets and liabilities --			
(Increase) decrease in accounts receivable	16,207,377	(14,308,274)	(2,889,530)
Increase in accounts payable and accrued liabilities, excluding income taxes payable	12,984	1,601,042	4,850,036
Increase (decrease) in income taxes payable	(306,983)	47,213	--
Net Cash Provided by Operating Activities	139,884,255	128,197,227	73,603,426
Cash Flows from Investing Activities:			
Additions to property and equipment	(275,126,333)	(173,277,356)	(78,112,550)
Proceeds from the sale of property and equipment	9,274,440	3,844,375	4,531,935
Net cash received as operator of oil and gas properties	5,927,539	19,769,213	5,995,842
Net cash received (distributed) as operator of partnerships and joint ventures	(3,574,601)	2,674,593	(433,114)
Other	(534,898)	(1,329)	(131,135)
Net Cash Used in Investing Activities	(264,033,853)	(146,990,504)	(68,149,022)
Cash Flows from Financing Activities:			
Proceeds from (payments of) long-term debt	--	(15,203,000)	124,045,000
Net proceeds from (payments of) bank borrowings	123,400,000	10,600,000	(146,200,000)
Net proceeds from issuances of common stock	1,633,508	2,697,561	42,719,776
Purchase of treasury stock	--	--	(1,462,740)
Payments of debt issuance costs	(721,756)	--	(3,501,441)
Net Cash Provided by (Used in) Financing Activities	124,311,752	(1,905,439)	15,600,595
Net Increase (Decrease) in Cash and Cash Equivalents	$ 162,154	$ (20,698,716)	$ 21,054,999
Cash and Cash Equivalents at Beginning of Year	1,986,932	22,685,648	1,630,649

Cash and Cash Equivalents at End of Year......	$ 2,149,086	$ 1,986,932	$ 22,685,648
Supplemental Disclosures of Cash Flows Information:			
Cash paid during year for interest, net of amounts capitalized........................	$ 12,207,205	$ 15,528,280	$ 8,618,020
Cash paid during year for income taxes........	$ 441,926	$ --	$ --
Non-Cash Financing Activity:			
Conversion of convertible notes to common stock.....................................	$ --	$ 99,797,000	$ --

See accompanying Notes to Consolidated Financial Statements.

SWIFT ENERGY COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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 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. Certain reclassifications have been made to prior year amounts to conform to current year presentation.

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, equipment, and certain general and administrative costs directly associated with acquisition, exploration, and development activities. Interest costs related to unproved properties are also capitalized to unproved oil and gas properties. 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. The proceeds from the sale of oil and gas properties are generally treated as a reduction of oil and gas property costs. Fees from associated oil and gas exploration and development limited partnerships are credited to oil and gas property costs to the extent they do not represent reimbursement of general and administrative expenses currently charged to expense.

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. The vast majority of our properties are onshore, and historically the salvage value of the tangible equipment offsets our site restoration and dismantlement and abandonment costs.

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, 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. All other equipment is 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, among other factors, 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 income.

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 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 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.

In addition, any unsuccessful exploratory well costs in countries in which there are no proved reserves are charged to expense as incurred. During the second quarter of 1999, we charged to income as additional depreciation, depletion, and amortization costs our portion of drilling costs associated with an unsuccessful exploratory well drilled by another operator in New Zealand. This charge was $290,000.

Because of the delineation of our 1999 Rimu discovery with two successful delineation wells drilled in 2000, proved reserves were recognized in New Zealand as of December 31, 2000.

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

OIL AND GAS REVENUES. Oil and gas revenues are reported, 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, 2001, 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 November 1996 of our 6.25% Convertible Subordinated Notes (the "Convertible Notes"), with the public offering in August 1999 of our 10.25% Senior Subordinated Notes (the "Senior Notes"), and with our September 2001 extension of our bank credit facility 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 mature on August 1, 2009, and the balance of their issuance costs at December 31, 2001, was $2,956,306, net of accumulated amortization of $545,135. The issuance costs associated with our revolving credit facility, which closed in September 2001, have been capitalized and are being amortized over the original life of the facility. The balance of revolving credit facility issuance costs at December 31, 2001, was $766,876, net of accumulated amortization of $513,573.

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 2001, we continue to serve as managing general partner of 71 of these various partnerships, and during fiscal 2001 approximately 2.9% 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 properties or their interests in the partnerships and dissolve. During 2001, seven drilling partnerships and two production purchase partnerships were dissolved. We anticipate that the liquidation and dissolution of the additional 65 partnerships will be completed by the end of 2002. The remaining six partnerships will continue to operate until their limited partners vote otherwise.

PRICE-RISK MANAGEMENT ACTIVITIES. In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." The statement 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. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows the gains and losses on derivatives to offset related results on the hedged item in the income statements and requires that a company must 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 policy to use derivative instruments, mainly the buying of protection price floors, to protect against price declines in oil and gas prices. We elected not to designate our price floors for special hedge accounting treatment under SFAS No. 133, as amended. However, we have elected to use mark-to-market accounting treatment for our derivative contracts. 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 2001 we recognized net gains of $1,173,094 relating to our derivative activities, with $16,784 in unrealized losses at year-end 2001. This activity is recorded in Price-risk management and other, net on the accompanying statements of income.

At December 31, 2001, we had open price floor contracts covering notional volumes of 2.0 million MMBtu of natural gas. These natural gas price floor contracts relate to the NYMEX contract months of February and March 2002 at an average price of $2.33 per MMBtu. The fair value of our open price floor contracts at December 31, 2001, totaled $296,000 and is included in Other current assets on the accompanying balance sheets.

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 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. During 1999, oil and gas sales to subsidiaries of Eastex Crude Company were $21.7 million, or 19.4% of our 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.

RISK FACTORS. Our revenues, profitability and cash flow are substantially dependent upon the price of and demand for oil and gas. Prices for oil and gas are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty, and a variety of additional factors beyond our control. We are also dependent upon the continued success of our domestic and New Zealand exploration and development programs. Other factors that could affect revenues, profitability, and cash flow include the inherent uncertainty in reserves estimates, our price-risk management activities, and the ability to replace reserves and finance our growth.

FAIR VALUE OF FINANCIAL INSTRUMENTS. 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, 2001 and 2000, 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 values of our Senior Notes were $126.5 million and $115.1 million at December 31, 2001 and 2000, respectively. The carrying value of our Senior Notes was $124.2 million and $124.1 million at December 31, 2001 and 2000, respectively.

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. We currently do not include dismantlement and abandonment costs in our depletion calculation as the vast majority of our properties are onshore and the salvage value of the tangible equipment offsets our dismantlement and abandonment costs. This standard will require us to

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

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, with earlier application encouraged. The Company is currently evaluating the effect of adopting Statement No. 143 on its financial statements and will adopt the statement on January 1, 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 1999 and 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. The assumed conversion of our Convertible Notes applies only to the 2000 period since for the 1999 period they would have been antidilutive and since they were extinguished at year end 2000. Certain of our stock options that would potentially dilute Basic EPS in the future were also antidilutive for the 2001 and 1999 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, 2001, 2000, and 1999:

	2001			2000			
	NET LOSS	SHARES	PER SHARE AMOUNT	NET INCOME	SHARES	PER SHARE AMOUNT	N
BASIC EPS:							
Net Income (Loss) and Share Amounts......	$(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......	--	--		--	713,112		
DILUTED EPS:							
Net Income (Loss) and Assumed Share Conversions........	$(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,		
	2001	2000	1999

Current	$ 114,611	$ (29,000)	$ (11,819)
Deferred	(12,352,047)	33,294,480	10,461,396
Total	$(12,237,436)	$33,265,480	$10,449,577

There are differences between income taxes computed using the federal statutory rate (35% for 2001, 2000, and 1999) and our effective income tax rates (35.8%, 35.7%, and 35.1% for 2001, 2000, and 1999, respectively), primarily as the result of state income taxes, foreign income taxes and certain tax credits available to the Company. Foreign net income for Swift Energy New Zealand Limited for 2001 was

$1,234,919. New Zealand's statutory rate and effective tax rate are 33%. Reconciliations of income taxes computed using the statutory rate to the effective income tax rates are as follows:

	2001	2000	1999
Income taxes computed at U.S. statutory rate	$(11,967,317)	$32,577,772	$10,407,653
State tax provisions, net of federal benefits	(279,875)	775,850	(7,801)
Provision for foreign income tax	(24,698)	--	--
Other, net	34,454	(88,142)	49,725
Provision (benefit) for income taxes	$(12,237,436)	$33,265,480	$10,449,577

The tax effects of temporary differences representing the net deferred tax liability (asset) at December 31, 2001 and 2000, were as follows:

	2001	2000
Deferred tax assets:		
Alternative minimum tax credits	$ (1,979,399)	$ (1,979,399)
Net operating loss carry forward	(18,877,969)	(16,194,060)
Total deferred tax assets	$(20,857,368)	$(18,173,459)
Deferred tax liabilities:		
Domestic oil and gas properties	$ 47,539,564	$ 59,097,793
Foreign oil and gas properties	407,524	--
Other	482,513	254,256
Total deferred tax liabilities	$ 48,429,601	$ 59,352,049

Net deferred tax liability....................	$ 27,572,233	$ 41,178,590

As of December 31, 2001, we had $52.7 million of net operating loss carry forwards, which expire as follows: $29.0 million, $20.1 million, $3.0 million and $0.6 million in 2013, 2014, 2015 and 2016, respectively.

We did not record any valuation allowances against deferred tax assets at December 31, 2001 and 2000.

At December 31, 2001, we had alternative minimum tax credits of $1,979,399 that carry forward indefinitely and are available to reduce future regular tax liability to the extent they exceed the related tentative minimum tax otherwise due.

4. LONG-TERM DEBT

Our long-term debt as of December 31, 2001 and 2000, is as follows:

	2001	2000
Bank Borrowings..	$134,000,000	$ 10,600,000
Senior Notes...	124,197,128	124,129,485
Long-Term Debt................................	$258,197,128	$134,729,485

BANK BORROWINGS. At December 31, 2001, we had outstanding borrowings of $134.0 million under our $250.0 million credit facility with a syndicate of nine banks which has a borrowing base of $200 million. At December 31, 2000, we had borrowings of $10.6 million under our credit facility. The interest rate is either (a) the lead bank's prime rate (4.75% at December 31, 2001) 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%. Of the $10.6 million borrowed at December 31, 2000, $5.0 million was borrowed at the LIBOR rate plus applicable margin (which averaged 7.89% at December 31, 2000).

Upon closing of the New Zealand TAWN acquisition in January 2002, our credit facility increased to $300.0 million and the borrowing base increased to $275.0 million. For further information on this acquisition, see Footnote 9 "Subsequent Events."

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), 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. Effective September 28, 2001, the credit facility was extended until October 1, 2005.

Interest expense on the credit facility, including commitment fees and amortization of debt issuance costs, totaled $5,833,564 in 2001, $654,936 in 2000, and $6,107,270 in 1999.

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 and $7,569,361 in 1999.

SENIOR NOTES. Our Senior Notes consist of $125.0 million of 10.25% Senior Subordinated Notes due 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. In addition, prior to August 1, 2002, we may redeem up to 33.33% of the Senior Notes with the proceeds of qualified offerings of our equity at 110.25% 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.

Interest expense on the Senior Notes, including amortization of debt issuance costs and discount, totaled $13,123,052 in 2001, $13,092,127 in 2000, and $5,303,266 in 1999.

DEBT MATURITIES. Our bank borrowings are due in October 2005, and our Senior Notes are due in August 2009.

5. COMMITMENTS AND CONTINGENCIES

Total rental and lease expenses were $1,322,611 in 2001, $1,255,474 in 2000, and $1,272,497 in 1999. Our remaining minimum annual obligations under non-cancelable operating lease commitments are $1,393,095 for 2002, $1,480,092 for 2003, $1,492,268 for 2004, and $248,711 for 2005. 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.

As of December 31, 2001, we were the managing general partner of 71 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. During the third quarter of 1999, we issued 4.6 million shares of common stock at a price of $9.75 per share. Gross proceeds from this offering were $44,850,000 with issuance costs of $2,888,690.

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.

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 plan. In addition, we have an employee stock purchase plan. No further grants will be made under the 1990 stock compensation 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 may be granted options to purchase shares of common stock. 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 22,360 shares at a price of $21.41 in 2001, 29,889 shares at a price range of $8.40 to $10.57 in 2000, and 22,771 shares at a price range of $5.21 to $11.00 in 1999. The estimated weighted average fair value of shares issued under this plan, as determined using the Black-Scholes option-pricing model, was $8.19 in 2001, $4.25 in 2000, and $4.74 in 1999. As of December 31, 2001, 362,428 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:

	2001	2000	1999
Net Income (Loss)			
As Reported..............................	$(22,347,765)	$59,184,008	$19,286,574
Pro Forma................................	$(26,632,624)	$56,531,665	$16,869,122
Basic EPS:			
As Reported..............................	$ (0.90)	$ 2.79	$ 1.07
Pro Forma................................	$ (1.08)	$ 2.66	$ 0.93
Diluted EPS:			
As Reported..............................	$ (0.90)	$ 2.51	$ 1.07
Pro Forma................................	$ (1.08)	$ 2.40	$ 0.93

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, 2001, 2000, and 1999:

	2001		2000		
	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHARES	WEIGHTED AVERAGE EXERCISE PRICE	SHAR
Options outstanding, beginning of period................................	2,076,593	$11.70	2,148,511	$ 9.08	2,266
Options granted..........................	747,073	$31.51	645,944	$16.88	25
Options canceled.........................	(31,247)	$14.09	(174,412)	$ 8.71	(77
Options exercised........................	(152,915)	$ 8.69	(543,450)	$ 8.48	(65
Options outstanding, end of period.......	2,639,504	$17.44	2,076,593	$11.70	2,148

Options exercisable, end of period.......	1,181,141	$11.49	897,711	$ 9.35	1,280
Options available for future grant, end of period............................	1,155,057		181,235		950
Estimated weighted average fair value per share of options granted during the year................................	$ 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 2001, 2000, and 1999, respectively: no dividend yield; expected volatility factors of 46.9%, 46.7%, and 44.2%; risk-free interest rates of 5.24%, 6.61%, and 5.60%; and expected lives of 7.3, 6.7, and 7.5 years. The following table summarizes information about stock options outstanding at December 31, 2001:

	OPTIONS OUTSTANDING			OPTIONS
RANGE OF EXERCISE PRICES	NUMBER OUTSTANDING AT DECEMBER 31, 2001	WEIGHTED AVERAGE REMAINING CONTRACTUAL LIFE	WEIGHTED AVERAGE EXERCISE PRICE	NUMBER EXERCISABLE DECEMBER 3 2001
$ 5.00 to $16.99....................	1,592,597	5.7	$ 9.50	1,012,907
$17.00 to $28.99....................	280,439	6.1	$23.25	153,785
$29.00 to $41.00....................	766,468	9.1	$31.84	14,449
$ 5.00 to $41.00....................	2,639,504	6.8	$17.44	1,181,141

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, 2001, 2000 and 1999, 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 $558,000, $483,000, and $474,000 for the years ended

December 31, 2001, 2000, and 1999, respectively. The contribution in 2001 was made all in common stock, while the 2000 and 1999 contributions were made half in common stock and half in cash. The shares of common stock contributed to the 401(k) savings plan totaled 28,798, 7,175, and 21,810 shares for the 2001, 2000, and 1999 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, 2001, 839,034 shares remain in treasury (net of 88,740 shares used to fund ESOP and 401(k) contributions) with a total cost of $12,032,791 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 joint ventures and, accordingly, charge these entities and third-party joint interest owners operating fees. The operating fees charged to the partnerships in 2001, 2000, and 1999 totaled approximately $925,000, $1,775,000, and $1,970,000, respectively. We are also reimbursed for direct, administrative, and overhead costs incurred in conducting the business of the limited partnerships, which totaled approximately $3,140,000, $4,465,000, and $4,000,000 in 2001, 2000, and 1999, 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 $2,360,000, $1,220,000, and $850,000 in 2001, 2000, and 1999, respectively.

8. FOREIGN ACTIVITIES

New Zealand

Swift Operated Permits. Our activity in New Zealand began in 1995 with the issuance of the first of two petroleum exploration permits. After surrendering a portion of our permit acreage in 1998, combining the two permits and expanding the permit acreage in 1999, and relinquishing 50% of the acreage in 2001 as we extended our petroleum exploration permit, our permit 38719 as of year end 2001 covered approximately 50,300 acres in the Taranaki Basin of New Zealand's north island, with all but 12,800 acres onshore. At December 31, 2001, we had a 90% working interest in this permit and had fulfilled all current obligations under this permit.

In late 1999, we completed our first exploratory well on this permit, the Rimu-A1, and a production test was performed. During the second half of 2000, we drilled and successfully tested two development wells, the Rimu-B1 and the Rimu-B2. In 2001 we drilled and tested three more Rimu development wells, the Rimu-A2, Rimu-A3 and Rimu-B3. The Rimu-A3 was successful; the Rimu-A2 and Rimu-B3 were dry. Early in 2002, the Rimu-A2 was sidetracked to the Tariki sand and is currently awaiting completion. The Rimu-B3 was also sidetracked in early

2002 and again was unsuccessful. In 2001, we also drilled the Kauri-A1 exploratory well, the Kauri-A2 development well, and the Kauri-B1 exploratory well. In the Kauri-A-1 we tested the Upper Tariki sands and still have further zones to test. The Kauri-A2 well

successfully tested the Manutahi sands. The Kauri-B1 was drilled approximately 1.75 miles to the southeast of the Kauri-A pad and targeted the Manutahi sands. This well was plugged and abandoned in 2001. Our portion of the drilling, completion, and testing costs incurred on the wells within our permits during 2001 was approximately $26.0 million. Our portion of prospect costs on our permits during 2001 was approximately $5.1 million, which included obtaining 2-D seismic data in the last half of the year for the Rata prospect. We incurred $22.5 million on the production facilities that we expect to be commissioned near the end of the first quarter of 2002.

In 2000, we entered into an agreement with Fletcher Challenge Energy Limited whereby we would earn a 25% participating interest in petroleum exploration permit 38730 containing approximately 48,900 acres. In May 2001, Fletcher relinquished their interest in the permit, and we then assumed 100% working interest in such permit by means of committing to an acceptable work plan. Such plan required us to acquire a minimum of 30 kilometers of new 2D seismic data, which we completed in 2001. Rather than commit to drill a new well in 2002 as the work plan called for, we surrendered this project in February 2002.

Non-Operated Permits. In 1998, we entered into agreements for a 25% working interest in an exploration permit, permit 38712, held by Marabella Enterprises Ltd., a subsidiary of Bligh Oil & Minerals, an Australian company, and a 7.5% working interest held by Antrim Oil and Gas Limited, a Canadian company, in a second permit, permit 38716, operated by Marabella. In turn, Bligh and Antrim each became 5% working interest owners in our permit 38719. Unsuccessful exploratory wells were drilled on these two permits, and we charged $0.4 million against earnings in 1998 and $0.3 million in 1999. All of the acreage on the permit 38712 was surrendered in 2000. The exploratory well on permit 38716 has been temporarily abandoned pending a further evaluation. It is currently anticipated that this well will be re-entered and sidetracked to target a location to the west of the initial well. A five-year extension was granted on permit 38716 in 2001 upon the surrender of 50% of the acreage.

In 2000, we entered into an agreement with Fletcher Challenge Energy Limited whereby we will earn a 20% participating interest in petroleum exploration permit 38718 containing approximately 57,400 acres. In January 2001, the operator temporarily abandoned the Tuihu #1 exploratory well on permit 38718 pending further analysis. The permit now contains approximately 28,700 acres after a scheduled surrender during December 2000.

Costs Incurred. During 2001, our costs incurred in New Zealand totaled $54.5 million, including $25.7 million for drilling, $5.5 million for prospect costs, $22.5 million for production facilities, and $0.8 million in evaluation costs for the acquisition of the TAWN assets, which closed in January 2002. These costs also included $0.6 million of costs incurred on permits operated by others: $0.2 million of drilling costs and $0.4 million of prospect costs. As of December 31, 2001, our investment in New Zealand totaled approximately $84.4 million. As we have recorded proved undeveloped reserves relating to our successful drilling activities, $45.5 million of our investment costs has been included in the proved properties portion of oil and gas properties and $38.8

million has been included as unproved properties at the end of 2001. Our development strategy includes having Rimu/Kauri production on line for oil and gas sales in New Zealand near the end of the first quarter of 2002.

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. We retain a minimum 6% net profits interest from the sale of hydrocarbon products from the fields. The value of our net profits interest depends upon either the successful development of production from the fields by others or their sale of the fields.

9. SUBSEQUENT EVENTS

TAWN ACQUISITION. Through our subsidiary, Swift Energy New Zealand Limited, we acquired Southern Petroleum Exploration Limited ("Southern NZ") from an affiliate of Shell New Zealand in January 2002 for approximately $54.4 million. Through Southern NZ we now own interests in four onshore producing oil and gas fields, extensive associated hydrocarbon-processing facilities and pipelines complementing our existing fields by providing us with access to export terminals and markets and additional excess processing capacity for both oil and natural gas. As of December 31, 2001, the reserves associated with this acquisition were estimated to be approximately 62.1 Bcfe, all of which were proved developed. This acquisition was accounted for using the purchase method of accounting. Upon the closing of this acquisition, our credit facility was increased to $300.0 million, and the borrowing base became $275.0 million.

In conjunction with the TAWN acquisition, we granted Shell New Zealand a short-term option to acquire an undivided 25% interest in our permit 38719, which includes our Rimu and Kauri areas, as well as a 25% interest in our Rimu Production Station. We do not know if Shell New Zealand will exercise this option. Any exercise of the option would be subject to numerous notifications, governmental approvals and consents. If Shell New Zealand does not exercise its option, we intend to pursue discussions with several other companies that have expressed interest in acquiring up to a 25% interest in the permit.

ANTRIM ACQUISITION. We purchased through our subsidiary, Swift Energy New Zealand Limited, all of the New Zealand assets owned by Antrim Oil and Gas Limited for 220,000 shares of Swift Energy Company common stock and an effective date adjustment of approximately $530,000. Antrim owned a 5% interest in permit 38719 and a 7.5% interest in permit 38716. As of December 31, 2001, the reserves associated with this acquisition were estimated to be approximately 5.7 Bcfe. This transaction closed in March 2002 (unaudited).

RUSSIA. On March 28, 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 Russian joint stock company, which owned and operated this field. This will result in a $7.5 million non-recurring, pre-tax gain in the first quarter of 2002 (unaudited).

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, 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
DECEMBER 31, 2000			
Proved oil and gas properties....................	$ 753,426,124	$ 732,265,674	$21,160,450
Unproved oil and gas properties..................	55,512,872	46,833,274	8,679,598
	808,938,996	779,098,948	29,840,048
Accumulated depreciation, depletion, and amortization..................................	(284,886,168)	(284,886,168)	--
Net capitalized costs..................	$ 524,052,828	$ 494,212,780	$29,840,048

Of the $57,096,694 of domestic unproved property costs (primarily seismic and lease acquisition costs) at December 31, 2001, excluded from the amortizable base, $26,707,313 was incurred in 2001, $9,545,964 was incurred in 2000, $5,640,587 was incurred in 1999, and $15,202,830 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. In response to market conditions in 1998, we decreased our 1999 drilling expenditures when compared to prior years, which, when coupled with the $15.3 million of leasehold properties acquired in the Brookeland and Masters Creek areas in 1998, may extend the evaluation time frame of such costs. Consequently, in response to market conditions, we have decreased our 2002 drilling expenditures as well.

Of the $38,846,469 of net New Zealand unproved property costs at December 31, 2001, excluded from the amortizable base, $30,383,713 was incurred in 2001, $5,013,539 was incurred in 2000, $907,972 was incurred in 1999, and $2,541,245 was incurred in prior years. We expect to continue drilling in New Zealand to delineate our prospects there, with seven wells planned for drilling in 2002. We expect to complete our evaluation of current unevaluated costs over the next two to three years. Upon the startup of the Rimu Production Station near the end of the first quarter of 2002, $23.6 million of these unproved property costs will be moved to the proved properties classification and will begin being depreciated.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

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

	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

	YEAR ENDED DECEMBER 31, 1999		
	TOTAL	DOMESTIC	NEW ZEALAND
Acquisition of proved properties	$ 18,526,939	$ 18,526,939	$ --
Lease acquisitions(1)	10,382,672	9,251,658	1,131,014

Exploration	11,019,430	5,101,330	5,918,100
Development	39,891,868	39,891,868	--
Total acquisition, exploration, and development(2)	$ 79,820,909	$ 72,771,795	$ 7,049,114
Processing plants	$ 1,607,559	$ 1,607,559	$ --
Field compression facilities	171,535	171,535	--
Total plants and facilities	$ 1,779,094	$ 1,779,094	$ --
Total costs incurred	$ 81,600,003	$ 74,550,889	$ 7,049,114

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(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 2001, 2000, and 1999 were $22,470,263, $16,791,834, and $14,389,680, respectively.

(2) Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately $11,600,000, $10,300,000, and $8,500,000 in 2001, 2000, and 1999, respectively. In addition, total includes $6,256,222, $5,043,206, and $4,142,098 in 2001, 2000, and 1999, 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 and 1999 were domestic. The following table sets forth results of our oil and gas operations:

	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	$ --

	YEAR ENDED DECEMBER 31, 1999		
	TOTAL	DOMESTIC	NEW ZEALAND
Oil and gas sales	$108,898,696	$108,898,696	$ --
Oil and gas production costs	(19,645,740)	(19,645,740)	--
Depreciation and depletion	(41,410,106)	(41,410,106)	--
	47,842,850	47,842,850	--
Provision for income taxes	16,792,840	16,792,840	--
Results of producing activities	$ 31,050,010	$ 31,050,010	$ --
Amortization per physical unit of production (equivalent Mcf of gas)	$ 0.97	$ 0.97	$ --

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 14, 2002, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 2001, and includes definitions and assumptions that served as the basis for the audit of proved reserves and future net cash flows. Such definitions and assumptions should be referred to in connection with the following information:

Estimates of Proved Reserves

	TOTAL	DOMESTIC

	NATURAL GAS (MCF)	OIL, NGL, AND CONDENSATE (BBLS)	NATURAL GAS (MCF)	OIL, NGL, AND CONDENSATE (BBLS)
Proved reserves as of December 31, 1998(1)	352,400,835	13,957,925	352,400,835	13,957,925
Revisions of previous estimates(2)	(31,189,450)	2,058,725	(31,189,450)	2,058,725
Purchases of minerals in place	9,159,780	1,822,858	9,159,780	1,822,858
Sales of minerals in place	(3,762,799)	(260,287)	(3,762,799)	(260,287)
Extensions, discoveries, and other additions	30,107,908	5,791,966	30,107,908	5,791,966
Production(3)	(26,756,524)	(2,564,924)	(26,756,524)	(2,564,924)
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
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
Revisions of previous estimates(2)	(122,127,541)	5,621,556	(101,693,477)	8,460,690
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
Production	(26,458,958)	(3,055,373)	(26,458,958)	(2,971,112)
Proved reserves as of December 31, 2001(4)	324,912,125	53,482,636	288,489,500	42,564,733
Proved developed reserves:				
December 31, 1998	197,105,963	7,142,566	197,105,963	7,142,566
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(4)	181,651,578	23,759,574	167,401,736	20,393,142

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(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, 2001, were based upon prices in effect at year end. The weighted average of such year end prices for total, domestic, and New Zealand were $2.51, $2.68, and $1.18 per Mcf of natural gas and $18.45, $18.51, and $18.25 per barrel of oil, respectively. This compares to $9.86, $11.25, and $0.71 per Mcf and $24.62, $25.50, and $22.30 per barrel as of December 31, 2000, for total, domestic, and New Zealand, respectively.

(3) Natural gas production for 1999 and 2000 excludes 728,235 and 405,130 Mcf,

respectively, delivered under our volumetric production payment agreement.

(4) We acquired 62.1 Bcfe and 5.7 Bcfe from the TAWN and Antrim acquisitions, respectively, in New Zealand. These reserves estimates at December 31, 2001, are not included in the above table. The TAWN reserves were all proved developed while the Antrim reserves were 34% proved developed.

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SWIFT ENERGY COMPANY AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS -- (CONTINUED)

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, 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

	YEAR ENDED DECEMBER 31, 1999		
	TOTAL	DOMESTIC	NEW ZEALAND
Future gross revenues	$1,371,541,850	$1,371,541,850	$ --
Future production costs	(353,594,258)	(353,594,258)	--
Future development costs	(156,738,446)	(156,738,446)	--
Future net cash flows before income taxes	861,209,146	861,209,146	--
Future income taxes	(226,725,033)	(226,725,033)	--
Future net cash flows after income taxes	634,484,113	634,484,113	--
Discount at 10% per annum	(195,540,279)	(195,540,279)	--
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 438,943,834	$ 438,943,834	$ --

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 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. 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 reserve estimates.

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

	YEAR ENDED DECEMBER 31,		
	2001	2000	1999
Beginning balance	$ 1,577,958,466	$ 438,943,834	$290,273,103
Revisions to reserves proved in prior years --			
Net changes in prices, production costs, and future development costs	(1,692,627,074)	1,523,487,598	123,447,890
Net changes due to revisions in quantity estimates	(93,669,181)	(36,102,814)	(23,746,974
Accretion of discount	231,325,481	56,405,451	34,078,501
Other	(204,768,815)	(220,119,873)	2,032,696
Total revisions	(1,759,739,589)	1,323,670,362	135,812,113
New field discoveries and extensions, net of future production and development costs	110,213,160	359,265,150	102,582,467
Purchases of minerals in place	39,544,163	160,240,785	39,282,292
Sales of minerals in place	(50,131,970)	(598,021)	(5,360,428
Sales of oil and gas produced, net of production costs	(144,262,145)	(159,331,003)	(88,196,672
Previously estimated development costs incurred	94,107,760	65,953,028	39,149,732
Net change in income taxes	586,868,060	(610,185,669)	(74,598,773
Net change in standardized measure of discounted future net cash flows	(1,123,400,561)	1,139,014,632	148,670,731
Ending balance	$ 454,557,905	$ 1,577,958,466	$438,943,834

QUARTERLY RESULTS. The following table presents summarized quarterly financial information for the years ended December 31, 2000 and 2001:

	INCOME/	BASIC EPS INCOME/

	REVENUES	INCOME/ (LOSS) BEFORE INCOME TAXES	(LOSS) BEFORE EXTRA-ORDINARY ITEM AND CHANGE IN ACCOUNTING PRINCIPLE	NET INCOME/ (LOSS)	(LOSS) BEFORE EXTRA-ORDINARY ITEM AND CHANGE IN ACCOUNTING PRINCIPLE
2000					
First Quarter.........	$ 37,747,645	$ 14,919,044	$ 9,589,828	$ 9,589,828	$ 0.46
Second Quarter........	46,127,375	22,218,358	14,213,274	14,213,274	0.68
Third Quarter.........	49,525,166	24,748,163	15,832,348	15,832,348	0.74
Fourth Quarter........	58,224,760	31,193,781	20,178,416	19,548,558	0.93
Total.........	$191,624,946	$ 93,079,346	$ 59,813,866	$ 59,184,008	$ 2.82
2001					
First Quarter.........	$ 62,392,014	$ 35,513,130	$ 22,719,653	$ 22,326,785	$ 0.92
Second Quarter........	52,303,265	23,408,900	14,972,946	14,972,946	0.61
Third Quarter.........	41,244,583	11,607,563	7,420,090	7,420,090	0.30
Fourth Quarter........	27,867,628	(104,721,926)	(67,067,586)	(67,067,586)	(2.71)
Total.........	$183,807,490	$ (34,192,333)	$(21,954,897)	$(22,347,765)	$(0.89)

PROSPECTUS

$350,000,000

[SWIFT ENERGY COMPANY LOGO] SWIFT ENERGY COMPANY

DEBT SECURITIES
COMMON STOCK
PREFERRED STOCK
DEPOSITARY SHARES
WARRANTS

Swift Energy Company may offer and sell from time to time debt securities, common stock, preferred stock, depositary shares or warrants. We will provide specific terms of the offering and sale of these securities in supplements to this prospectus. These terms will include the initial offering price, aggregate amount of the offering, listing on any securities exchange or quotation system, risk factors and the agents, dealers or underwriters, if any, to be used in connection with the sale of these securities. Certain selling shareholders may also from time to time offer and sell common stock under this prospectus. You should read this prospectus and any supplement carefully before you invest.

Our common stock is traded on the New York Stock Exchange and the Pacific Stock Exchange under the symbol "SFY."

This prospectus may not be used to sell securities unless accompanied by a supplement to this prospectus.

NEITHER THE SECURITIES AND EXCHANGE COMMISSION NOR ANY STATE SECURITIES COMMISSION HAS APPROVED OR DISAPPROVED OF THESE SECURITIES, OR DETERMINED IF THIS PROSPECTUS IS TRUTHFUL OR COMPLETE. ANY REPRESENTATION TO THE CONTRARY IS A

CRIMINAL OFFENSE.

The date of this prospectus is July 23, 2001

YOU SHOULD RELY ONLY ON THE INFORMATION CONTAINED IN OR INCORPORATED BY REFERENCE IN THIS PROSPECTUS AND IN ANY PROSPECTUS SUPPLEMENT. WE HAVE NOT AUTHORIZED ANYONE TO PROVIDE YOU WITH DIFFERENT INFORMATION. WE ARE NOT MAKING AN OFFER OF THESE SECURITIES IN ANY STATE WHERE THE OFFER IS NOT PERMITTED. YOU SHOULD NOT ASSUME THAT THE INFORMATION CONTAINED IN OR INCORPORATED BY REFERENCE IN THIS PROSPECTUS IS ACCURATE AS OF ANY DATE OTHER THAN THE DATE ON THE FRONT OF THIS PROSPECTUS OR THE APPLICABLE PROSPECTUS SUPPLEMENT.

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ABOUT THIS PROSPECTUS

This prospectus is part of a registration statement that we filed with the Securities and Exchange Commission using a "shelf" registration process. Under the shelf process, we may sell any combination of the securities described in this prospectus in one or more offerings up to a total dollar amount of $350,000,000. In addition, under this shelf process, one or more selling shareholders may sell our common stock in one or more offerings, which will reduce the aggregate dollar amount we may sell. This prospectus provides you with a general description of the securities we may offer. Each time we sell securities, we will provide a prospectus supplement that will contain specific information about the terms of that offering. The prospectus supplement may also add, update or change information contained in this prospectus. You should read both this prospectus and any prospectus supplement, together with additional information described under the heading "WHERE YOU CAN FIND MORE INFORMATION."

As used in this prospectus, "Swift," "we," "us," and "our" refer to Swift Energy Company and its subsidiaries.

WHERE YOU CAN FIND MORE INFORMATION

We are subject to the informational requirements of the Securities Exchange Act of 1934, which requires us to file annual, quarterly and special reports, proxy statements and other information with the Securities and Exchange Commission, or the "SEC." You may read and copy any document that we file at the Public Reference Room of the SEC at 450 Fifth Street, N.W., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operation of its public reference room. You may also inspect our filings at the regional offices of the SEC located at Citicorp Center, 500 West Madison Street, Suite 1400, Chicago, Illinois 60661 and 7 World Trade Center, New York, New York 10048 or over the Internet at the SEC's web site at http://www.sec.gov, or at our own website at http://www.swiftenergy.com.

This prospectus constitutes part of a Registration Statement on Form S-3 filed with the SEC under the Securities Act of 1933. It omits some of the information contained in the Registration Statement, and reference is made to the Registration Statement for further information with respect to us and the securities we are offering. Any statement contained in this prospectus concerning the provisions of any document filed as an exhibit to the Registration Statement or otherwise filed with the SEC is not necessarily complete, and in each instance reference is made to the copy of the filed document.

The SEC allows us to "incorporate by reference" the information we file with them, which means that we can disclose important information to you by referring you to those documents. The information incorporated by reference is considered to be part of this prospectus, and later information that we file with the SEC will automatically update and supersede this information and the information in the prospectus. We incorporate by reference the documents listed below and any future filings made with the SEC under Sections 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934 until we sell all the securities covered by this prospectus:

1. Our Annual Report on Form 10-K for the year ended December 31, 2000;

2. Our Quarterly Report on Form 10-Q for the fiscal quarter ended March 31, 2001;

3. The description of our common stock contained in our registration statement on Form 8-A filed on July 24, 1981, as amended, including any amendment or report filed before or after the date of this prospectus for

the purpose of updating the description; and

4. The description of our preferred share purchase rights contained in our registration statement on Form 8-A filed on August 11, 1997, as amended on April 7, 1999, including any amendment or report filed before or after the date of this prospectus for the purpose of updating the description.

You may request a copy of these filings at no cost, by writing or telephoning Bruce H. Vincent, Executive Vice President -- Corporate Development, Swift Energy Company, Suite 400, 16825 Northchase Drive, Houston, Texas 77060, phone: (281) 874-2700.

RISK FACTORS

There are a number of risks associated with investing in Swift and in our industry. You should carefully review the more detailed description of risk factors contained in the supplement to this prospectus.

- Our revenue, profitability and cash flow depend upon the prices and demand for oil and gas. The markets for these commodities are very volatile and steep or prolonged drops in prices can harm us financially and hurt our ability to grow.

- Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Operating and developing oil and natural gas properties involves a number of inherent risks, including the risk of personal injury, environmental contamination or loss of wells. We may not be able to insure against all of these risks.

- Our significant growth in recent years is attributable in significant part to our acquiring producing properties. Our ability to continue to make successful acquisitions is influenced by many factors beyond our control. A failure to acquire producing properties on a profitable basis in the future may significantly affect our profitability and growth.

- Estimates of our proved developed oil and natural gas reserves and the resulting future net revenues contained in this prospectus and elsewhere are based on a number of uncertainties. A failure to realize our estimated prices or estimated production volumes could materially adversely affect our revenues, profitability and financial health.

- Our ability to conduct operations in a timely and cost effective manner depends on the availability of supplies, equipment and personnel. The oil and gas industry is cyclical and experiences periodic shortages of drilling rigs and other equipment, tubular goods, supplies and experienced personnel. Shortages can delay operations and materially increase operating and capital costs.

- We make, and will continue to make, substantial capital expenditures to acquire, develop, produce, explore and abandon our oil and natural gas reserves. Any decrease in our revenues, as a result of lower oil or gas prices or otherwise, could limit our ability to replace reserves or maintain production at current levels. If our cash flow from operations drops significantly, we may be unable to find additional debt or equity financing.

- Our future success depends on our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Failure to do so will result in lower production and cash flow.

FORWARD-LOOKING STATEMENTS

Some of the information included in this prospectus, any prospectus supplement and the documents we have incorporated by reference contain forward-looking statements. Forward-looking statements use forward-looking terms such as "believe," "expect," "may," "intend," "will," "project," "budget," "should" or "anticipate" or other similar words. These statements discuss "forward-looking" information such as:

- anticipated capital expenditures and budgets;

- future cash flows and borrowings;

- pursuit of potential future acquisition or drilling opportunities; and

- sources of funding for exploration and development.

These forward-looking statements are based on assumptions that we believe are reasonable, but they are open to a wide range of uncertainties and business risks, including the following:

- fluctuations of the prices received or demand for oil and natural gas;

- uncertainty of drilling results, reserve estimates and reserve replacement;

- operating hazards;

- acquisition risks;

- unexpected substantial variances in capital requirements;

- environmental matters; and

- general economic conditions.

Other factors that could cause actual results to differ materially from those anticipated are discussed in our periodic filings with the SEC, including our Annual Report on Form 10-K for the year ended December 31, 2000.

When considering these forward-looking statements, you should keep in mind the risk factors and other cautionary statements in this prospectus, any prospectus supplement and the documents we have incorporated by reference. We will not update these forward-looking statements unless the securities laws require us to do so.

THE COMPANY

Swift Energy Company, a Texas corporation, is engaged in the exploration, development, acquisition and operation of oil and gas properties. Historically, our primary focus has been on U.S. onshore natural gas reserves, although we are now also focusing on our operations in New Zealand and have interests offshore in the Gulf of Mexico. As of December 31, 2000, we had interests in 1,528 oil and gas wells located in eight states, offshore in the Gulf of Mexico and in New

Zealand. We operated 817 of these wells, representing 91% of our proved reserves. At such date, our estimated proved reserves were 629.4 Bcfe, of which approximately 67% was natural gas, with 54% of our reserves located in Texas, 22% in Louisiana and 20% in New Zealand.

Our core domestic areas for development and exploration drilling are the AWP Olmos Area located in South Texas and the Brookeland Area, the Giddings Area and the Masters Creek Area in the Austin Chalk trend in Texas and Louisiana. We expect our reserves in the AWP Olmos Field to be steadily produced over a long period. This offsets the Austin Chalk trend reserves, which have a high initial production but decline rapidly. The AWP Olmos Field accounted for approximately 37% of our proved reserves as of December 31, 2000 and approximately 32% of our 2000 production, while the Austin Chalk trend accounted for approximately 35% of our proved reserves as of December 31, 2000 and generated approximately 62% of our 2000 production. New Zealand accounted for approximately 20% of our proved reserves as of December 31, 2000 and had not yet produced as of December 31, 2000. Subsequent to year-end 2000, we acquired interests in Lake Washington Field in Louisiana for $30.5 million.

We have increased our proved reserves from 176.1 Bcfe at year-end 1995 to 629.4 Bcfe at year-end 2000, which represents the replacement of 375% of our production during the same period. Our five-year average reserves replacement costs were $0.94 per Mcfe. A combination of increased production and decreased operating costs per Mcfe resulted in average annual growth in net cash provided by operating activities of 55% per year from year-end 1995 to year-end 2000.

Swift's philosophy is to pursue a balanced growth strategy that includes an active drilling program, strategic acquisitions, and the utilization of advanced technologies. We seek to increase our reserves through both drilling and acquisitions, shifting the balance between the two activities in response to market conditions. For example, when oil and gas prices are low, we focus upon acquiring producing properties. When oil and gas prices are high, we shift our focus to drilling wells.

Following the fall in oil and gas prices during mid-1998, we grew primarily by increasing our acreage position, mainly through the Toledo Bend properties acquisition in Texas and Louisiana purchased from Sonat Exploration Company. Capital expenditures for development and exploration drilling were $67.4 million in 1998 and $44 million in 1999, while the amounts spent for acquisitions were $59.5 million in 1998 and $20.6 million in 1999. In 2000 drilling expenditures totaled $115.5 million, while $33.4 million was spent to acquire producing properties, primarily in the third quarter. Most of our drilling activities were in the AWP Olmos Field, the Austin Chalk trend and New Zealand.

Our principal executive offices are located at 16825 Northchase Drive, Suite 400, Houston, Texas 77060 and our telephone number is (281) 874-2700.

RATIO OF EARNINGS TO FIXED CHARGES

The following table sets forth our ratio of earnings to fixed charges:

	YEARS ENDED DECEMBER 31,					THREE MONTHS ENDED MARCH 31,	
	1996	1997	1998	1999	2000	2000	2001
Ratio of earnings to fixed charges.....	12.8x	5.2x	--	2.4x	5.2x	3.6x	9.1x

Due to the $90.8 million non-cash charge incurred in the year ended December 31, 1998 caused by a write down in the carrying value of natural gas and oil properties, 1998 earnings were insufficient by

$76.9 million to cover fixed charges in 1998. If the $90.8 million non-cash charge is excluded, the ratio of earnings to fixed charges would have been 2.1x.

For the purpose of computing the ratio of earnings to fixed charges, earnings are defined as:

- income from continuing operations before income taxes;

- plus fixed charges; and

- less capitalized interest.

Fixed charges are defined as the sum of the following:

- interest, including capitalized interest, on all indebtedness;

- amortization of debt issuance cost; and

- that portion of rental expense which we believe to be representative of an interest factor.

USE OF PROCEEDS

Unless we specify otherwise in an accompanying prospectus supplement, we intend to use the net proceeds we receive from the sale of securities offered by this prospectus and the accompanying prospectus supplement for the repayment of debt under our credit lines and for general corporate purposes. General corporate purposes may include additions to working capital, development and exploration expenditures or the financing of possible acquisitions. We will not receive any proceeds from any sale of common stock by selling shareholders.

The net proceeds may be invested temporarily until they are used for their stated purpose.

DESCRIPTION OF DEBT SECURITIES

This section describes the general terms and provisions of the debt securities which may be offered by us from time to time. The applicable prospectus supplement will describe the specific terms of the debt securities offered by that prospectus supplement.

We may issue debt securities either separately or together with, or upon the conversion of, or in exchange for, other securities. The debt securities are to be either senior obligations of ours issued in one or more series and referred to herein as the "Senior Debt Securities," or subordinated obligations of ours issued in one or more series and referred to herein as the "Subordinated Debt Securities." The Senior Debt Securities and the Subordinated Debt Securities are collectively referred to as the "Debt Securities." The Debt Securities will be general obligations of the Company. Each series of Debt Securities will be issued under an agreement, or "Indenture," between Swift and an independent third party, usually a bank or trust company, known as a "Trustee," who will be legally obligated to carry out the terms of the Indenture. The name(s) of the Trustee(s) will be set forth in the applicable prospectus supplement. We may issue all the Debt Securities under the same

Indenture, as one or as separate series, as specified in the applicable prospectus supplement(s).

This summary of certain terms and provisions of the Debt Securities and Indentures is not complete. If we refer to particular provisions of an Indenture, the provisions, including definitions of certain terms, are incorporated by reference as a part of this summary. The Indentures are or will be filed as an exhibit to the registration statement of which this prospectus is a part, or as exhibits to documents filed under the Securities Exchange Act of 1934 which are incorporated by reference into this prospectus. The Indentures are subject to and governed by the Trust Indenture Act of 1939, as amended. You should refer to the applicable Indenture for the provisions which may be important to you.

GENERAL

The Indentures will not limit the amount of Debt Securities which we may issue. We may issue Debt Securities up to an aggregate principal amount as we may authorize from time to time. The applicable prospectus supplement will describe the terms of any Debt Securities being offered, including:

- the title and aggregate principal amount;

- the date(s) when principal is payable;

- the interest rate, if any, and the method for calculating the interest rate;

- the interest payment dates and the record dates for the interest payments;

- the places where the principal and interest will be payable;

- any mandatory or optional redemption or repurchase terms or prepayment, conversion, sinking fund or exchangeability or convertibility provisions;

- whether such Debt Securities will be Senior Debt Securities or Subordinated Debt Securities and, if Subordinated Debt Securities, the subordination provisions and the applicable definition of "Senior Indebtedness";

- additional provisions, if any, relating to the defeasance and covenant defeasance of the Debt Securities;

- if other than denominations of $1,000 or multiples of $1,000, the denominations the Debt Securities will be issued in;

- whether the Debt Securities will be issued in the form of Global Securities, as defined below, or certificates;

- whether the Debt Securities will be issuable in registered form, referred to as "Registered Securities," or in bearer form, referred to as "Bearer Securities" or both and, if Bearer Securities are issuable, any restrictions applicable to the exchange of one form for another and the offer, sale and delivery of Bearer Securities;

- any applicable material federal tax consequences;

- the dates on which premiums, if any, will be payable;

- our right, if any, to defer payment of interest and the maximum length of such deferral period;

- any paying agents, transfer agents, registrars or trustees;

- any listing on a securities exchange;

- if convertible into common stock or preferred stock, the terms on which such Debt Securities are convertible;

- the terms, if any, of the transfer, mortgage, pledge, or assignment as security for any series of Debt Securities of any properties, assets, proceeds, securities or other collateral, including whether certain provisions of the Trust Indenture Act are applicable, and any corresponding changes to provisions of the Indenture as currently in effect;

- the initial offering price; and

- other specific terms, including covenants and any additions or changes to the events of default provided for with respect to the Debt Securities.

The terms of the Debt Securities of any series may differ and, without the consent of the holders of the Debt Securities of any series, we may reopen a previous series of Debt Securities and issue additional

Debt Securities of such series or establish additional terms of such series, unless otherwise indicated in the applicable prospectus supplement.

NON U.S. CURRENCY

If the purchase price of any Debt Securities is payable in a currency other than U.S. dollars or if principal of, or premium, if any, or interest, if any, on any of the Debt Securities is payable in any currency other than U.S. dollars, the specific terms with respect to such Debt Securities and such foreign currency will be specified in the applicable prospectus supplement.

ORIGINAL ISSUE DISCOUNT SECURITIES

Debt Securities may be issued as "Original Issue Discount Securities" to be sold at a substantial discount below their principal amount. Original Issue Discount Securities may include "zero coupon" securities that do not pay any cash interest for the entire term of the securities. In the event of an acceleration of the maturity of any Original Issue Discount Security, the amount payable to the holder thereof upon such acceleration will be determined in the manner described in the applicable prospectus supplement. Conditions pursuant to which payment of the principal of the Subordinated Debt Securities may be accelerated will be set forth in the applicable prospectus supplement. Material federal income tax and other considerations applicable to Original Issue Discount Securities will be described in the applicable prospectus supplement.

COVENANTS

Under the Indentures, we will be required to:

- pay the principal, interest and any premium on the Debt Securities when due;

- maintain a place of payment;

- deliver a report to the Trustee at the end of each fiscal year reviewing our obligations under the Indentures; and

- deposit sufficient funds with any paying agent on or before the due date for any principal, interest or any premium.

Any additional covenants will be described in the applicable prospectus supplement.

REGISTRATION, TRANSFER, PAYMENT AND PAYING AGENT

Unless otherwise indicated in a prospectus supplement, each series of Debt Securities will be issued in registered form only, without coupons. The Indentures, however, provide that we may also issue Debt Securities in bearer form only, or in both registered and bearer form. Bearer Securities shall not be offered, sold, resold or delivered in connection with their original issuance in the United States or to any United States person other than offices located outside the United States of certain United States financial institutions. "United States person" means any citizen or resident of the United States, any corporation, partnership or other entity created or organized in or under the laws of the United States, any estate the income of which is subject to United States federal income taxation regardless of its source, or any trust whose administration is subject to the primary supervision of a United States court and which has one or more United States fiduciaries who have the authority to control all substantial decisions of the trust. "United States" means the United States of America (including the states thereof and the District of Columbia), its territories, its possessions and other areas subject to its jurisdiction. Purchasers of Bearer Securities will be subject to certification procedures and may be affected by certain limitations under United States tax laws. Such procedures and limitations will be described in the prospectus supplement relating to the offering of the Bearer Securities.

Unless otherwise indicated in a prospectus supplement, Registered Securities will be issued in denominations of $1,000 or any integral multiple thereof, and Bearer Securities will be issued in denominations of $5,000.

Unless otherwise indicated in a prospectus supplement, the principal, premium, if any, and interest, if any, of or on the Debt Securities will be payable, and Debt Securities may be surrendered for registration of transfer or exchange, at an office or agency to be maintained by us in the Borough of Manhattan, The City of New York, provided that payments of interest with respect to any Registered Security may be made at our option by check mailed to the address of the person entitled to payment or by transfer to an account maintained by the payee with a bank located in the United States. No service charge shall be made for any registration of transfer or exchange of Debt Securities, but we may require payment of a sum sufficient to cover any tax or other governmental charge and any other expenses that may be imposed in connection with the exchange or transfer.

Unless otherwise indicated in a prospectus supplement, payment of principal of, premium, if any, and interest, if any, on Bearer Securities will be made, subject to any applicable laws and regulations, at such office or agency outside the United States as specified in the prospectus supplement and as we may designate from time to time. Unless otherwise indicated in a prospectus supplement, payment of interest due on Bearer Securities on any interest payment date will be made only against surrender of the coupon relating to such interest payment date. Unless otherwise indicated in a prospectus supplement, no payment of principal, premium or interest with respect to any Bearer Security will be made at any office or agency in the United States or by check mailed to any address in the United States or by transfer to an account maintained with a bank located in the United States; except that if amounts owing with respect to any Bearer Securities shall be payable in U.S. dollars, payment may be made at the Corporate Trust Office of the applicable Trustee or at any office or agency designated by us in the Borough of Manhattan, The City of New York, if (but only if) payment of the full amount of such principal, premium or interest at all offices outside of the United States maintained for such purpose by us is illegal or effectively precluded by exchange controls or similar restrictions.

Unless otherwise indicated in the applicable prospectus supplement, we will not be required to:

- issue, register the transfer of or exchange Debt Securities of any series during a period beginning at the opening of business 15 days before any selection of Debt Securities of that series of like tenor to be redeemed and ending at the close of business on the day of that selection;

- register the transfer of or exchange any Registered Security, or portion thereof, called for redemption, except the unredeemed portion of any Registered Security being redeemed in part;

- exchange any Bearer Security called for redemption, except to exchange such Bearer Security for a Registered Security of that series and like tenor that is simultaneously surrendered for redemption; or

- issue, register the transfer of or exchange any Debt Security which has been surrendered for repayment at the option of the holder, except the portion, if any, of the Debt Security not to be so repaid.

RANKING OF DEBT SECURITIES

The Senior Debt Securities will be unsubordinated obligations of ours and will rank equally in right of payment with all other unsubordinated indebtedness of ours. The Subordinated Debt Securities will be obligations of ours and will be subordinated in right of payment to all existing and future Senior Indebtedness. The prospectus supplement will describe the subordination provisions and set forth the definition of "Senior Indebtedness" applicable to the Subordinated Debt Securities, and will set forth the approximate amount of such Senior Indebtedness outstanding as of a recent date.

GLOBAL SECURITIES

The Debt Securities of a series may be issued in whole or in part in the form of one or more global securities that will be deposited with, or on behalf of, a "Depositary" identified in the prospectus supplement relating to such series. Global Debt Securities may be issued in either registered or bearer form and in either temporary or permanent form. Unless and until it is exchanged in whole or in part for individual certificates evidencing Debt Securities, a Global Debt Security may not be transferred except as a whole:

- by the Depositary to a nominee of such Depositary;

- by a nominee of such Depositary to such Depositary or another nominee of such Depositary; or

- by such Depositary or any such nominee to a successor of such Depositary or a nominee of such successor.

The specific terms of the depositary arrangement with respect to a series of Global Debt Securities and certain limitations and restrictions relating to a series of Global Bearer Securities will be described in the applicable prospectus supplement.

OUTSTANDING DEBT SECURITIES

In determining whether the holders of the requisite principal amount of outstanding Debt Securities have given any authorization, demand, direction, notice, consent or waiver under the relevant Indenture, the amount of outstanding Debt Securities will be calculated based on the following:

- the portion of the principal amount of an Original Issue Discount Security that shall be deemed to be outstanding for such purposes shall be that portion of the principal amount thereof that could be declared to be due and payable upon a declaration of acceleration pursuant to the terms of such Original Issue Discount Security as of the date of such determination;

- the principal amount of a Debt Security denominated in a currency other than U.S. dollars shall be the U.S. dollar equivalent, determined on the date of original issue of such Debt Security, of the principal amount of such Debt Security; and

- any Debt Security owned by us or any obligor on such Debt Security or any affiliate of us or such other obligor shall be deemed not to be outstanding.

REDEMPTION AND REPURCHASE

The Debt Securities may be redeemable at our option, may be subject to mandatory redemption pursuant to a sinking fund or otherwise, or may be subject to repurchase by Swift at the option of the holders, in each case upon the terms, at the times and at the prices set forth in the applicable prospectus supplement.

CONVERSION AND EXCHANGE

The terms, if any, on which Debt Securities of any series are convertible into or exchangeable for common stock, preferred stock, or other Debt Securities will be set forth in the applicable prospectus supplement. Such terms of conversion or exchange may be either mandatory, at the option of the holders, or at our option.

CONSOLIDATION, MERGER AND SALE OF ASSETS

Each Indenture generally will permit a consolidation or merger, subject to certain limitations and conditions, between us and another corporation. They also will permit the sale by us of all or substantially all of our property and assets. If this happens, the remaining or acquiring corporation shall assume all of

our responsibilities and liabilities under the Indentures including the payment of all amounts due on the Debt Securities and performance of the covenants in the Indentures.

We are only permitted to consolidate or merge with or into any other corporation or sell all or substantially all of our assets according to the terms and conditions of the Indentures, as indicated in the applicable prospectus supplement. The remaining or acquiring corporation will be substituted for us in the Indentures with the same effect as if it had been an original party to the Indenture. Thereafter, the successor corporation may exercise our rights and powers under any Indenture, in our name or in its own name. Any act or proceeding required or permitted to be done by our board of directors or any of our officers may be done by the board or officers of the successor corporation.

EVENTS OF DEFAULT

Unless otherwise specified in the applicable prospectus supplement, an Event of Default, as defined in the Indentures and applicable to Debt Securities issued under such Indentures, typically will occur with respect to the Debt Securities of any series under the Indenture upon:

- default for a period to be specified in the applicable prospectus supplement in payment of any interest with respect to any Debt Security of such series;

- default in payment of principal or any premium with respect to any Debt Security of such series when due upon maturity, redemption, repurchase at the option of the holder or otherwise;

- default in deposit of any sinking fund payment when due with respect to any Debt Security of such series;

- default by us in the performance, or breach, of any other covenant or warranty in such Indenture, which shall not have been remedied for a period to be specified in the applicable prospectus supplement after notice to us by the applicable Trustee or the holders of not less than a fixed percentage in aggregate principal amount of the Debt Securities of all series issued under the applicable Indenture;

- certain events of bankruptcy, insolvency or reorganization of Swift; or

- any other Event of Default that may be set forth in the applicable prospectus supplement, including an Event of Default based on other debt being accelerated, known as a "cross-acceleration."

No Event of Default with respect to any particular series of Debt Securities necessarily constitutes an Event of Default with respect to any other series of Debt Securities. If the Trustee considers it in the interest of the holders to do so, the Trustee under an Indenture may withhold notice of the occurrence of a default with respect to the Debt Securities to the holders of any series outstanding, except a default in payment of principal, premium, if any, interest, if any.

Each Indenture will provide that if an Event of Default with respect to any series of Debt Securities issued thereunder shall have occurred and be continuing, either the relevant Trustee or the holders of at least a fixed percentage in principal amount of the Debt Securities of such series then outstanding may declare the principal amount of all the Debt Securities of such series to be due and payable immediately. In the case of Original Issue Discount Securities, the Trustee may declare as due and payable such lesser amount as may be specified in the applicable prospectus supplement. However, upon certain conditions, such declaration and its consequences may be rescinded and annulled by the holders of at least a fixed percentage in principal amount of the Debt Securities of all series issued under the applicable Indenture.

The applicable prospectus supplement will provide the terms pursuant to which an Event of Default shall result in acceleration of the payment of principal of Subordinated Debt Securities.

In the case of a default in the payment of principal of, or premium, if any, or interest, if any, on any Subordinated Debt Securities of any series, the applicable Trustee, subject to certain limitations and conditions, may institute a judicial proceeding for the collection thereof.

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No holder of any of the Debt Securities of any series will have any right to institute any proceeding with respect to the Indenture or any remedy thereunder, unless the holders of at least a fixed percentage in principal amount of the outstanding Debt Securities of such series:

- have made written request to the Trustee to institute such proceeding as Trustee, and offered reasonable indemnity to the Trustee,

- the Trustee has failed to institute such proceeding within the time period specified in the applicable prospectus supplement after receipt of such notice, and

- the Trustee has not within such period received directions inconsistent with such written request by holders of a majority in principal amount of the outstanding Debt Securities of such series. Such limitations do not apply, however, to a suit instituted by a holder of a Debt Security for the enforcement of the payment of the principal of, premium, if any, or any accrued and unpaid interest on, the Debt Security on or after the respective due dates expressed in the Debt Security.

During the existence of an Event of Default under an Indenture, the Trustee is required to exercise such rights and powers vested in it under the Indenture and use the same degree of care and skill in its exercise thereof as a prudent person would exercise under the circumstances in the conduct of such person's own affairs. Subject to the provisions of the Indenture relating to the duties of the Trustee, if an Event of Default shall occur and be continuing, the Trustee is under no obligation to exercise any of its rights or powers under the Indenture at the request or direction of any of the holders, unless such holders shall have offered to the Trustee reasonable security or indemnity. Subject to certain provisions concerning the rights of the Trustee, the holders of at least a fixed percentage in principal amount of the outstanding Debt Securities of any series have the right to direct the time, method and place of conducting any proceeding for any remedy available to the Trustee, or exercising any power conferred on the Trustee with respect to such series.

The Indentures provide that the Trustee will, within the time period specified in the applicable prospectus supplement after the occurrence of any default, give to the holders of the Debt Securities of such series notice of such default known to it, unless such default shall have been cured or waived; provided that the Trustee shall be protected in withholding such notice if it determines in good faith that the withholding of such notice is in the interest of such holders, except in the case of a default in payment of principal of or premium, if any, on any Debt Security of such series when due or in the case of any default in the payment of any interest on the Debt Securities of such series.

Swift is required to furnish to the Trustee annually a statement as to compliance with all conditions and covenants under the Indentures.

MODIFICATION AND WAIVERS

From time to time, when authorized by resolutions of our board of directors and by the Trustee, without the consent of the holders of Debt Securities of any series, we may amend, waive or supplement the Indentures and the Debt Securities of such series for certain specified purposes, including, among other things:

- to cure ambiguities, defects or inconsistencies;

- to provide for the assumption of our obligations to holders of the Debt Securities of such series in the case of a merger or consolidation;

- to add to our Events of Default or our covenants or to make any change that would provide any additional rights or benefits to the holders of the Debt Securities of such series;

- to add or change any provisions of such Indenture to facilitate the issuance of Bearer Securities;

- to establish the form or terms of Debt Securities of any series and any related coupons;

- to add guarantors with respect to the Debt Securities of such series;

- to secure the Debt Securities of such series;

- to maintain the qualification of the Indenture under the Trust Indenture Act; or

- to make any change that does not adversely affect the rights of any holder.

Other amendments and modifications of the Indentures or the Debt Securities issued thereunder may be made by Swift and the Trustee with the consent of the holders of not less than a fixed percentage of the aggregate principal amount of the outstanding Debt Securities of each series affected, with each series voting as a separate class; provided that, without the consent of the holder of each outstanding Debt Security affected, no such modification or amendment may:

- reduce the principal amount of, or extend the fixed maturity of the Debt Securities, or alter or waive any redemption, repurchase or sinking fund provisions of the Debt Securities;

- reduce the amount of principal of any Original Issue Discount Securities that would be due and payable upon an acceleration of the maturity thereof;

- change the currency in which any Debt Securities or any premium or the accrued interest thereon is payable;

- reduce the percentage in principal amount outstanding of Debt Securities of any series which must consent to an amendment, supplement or waiver or consent to take any action under the Indenture or the Debt Securities of such series;

- impair the right to institute suit for the enforcement of any payment on or with respect to the Debt Securities;

- waive a default in payment with respect to the Debt Securities or any guarantee;

- reduce the rate or extend the time for payment of interest on the Debt Securities;

- adversely affect the ranking of the Debt Securities of any series;

- release any guarantor from any of its obligations under its guarantee or the Indenture, except in compliance with the terms of the Indenture; or

- solely in the case of a series of Subordinated Debt Securities, modify any of the applicable subordination provisions or the applicable definition of Senior Indebtedness in a manner adverse to any holders.

The holders of a fixed percentage in aggregate principal amount of the outstanding Debt Securities of any series may waive compliance by us with certain restrictive provisions of the relevant Indenture, including any set forth in the applicable prospectus supplement. The holders of a fixed percentage in aggregate principal amount of the outstanding Debt Securities of any series may, on behalf of the holders of that series, waive any past default under the applicable Indenture with respect to that series and its consequences, except a default in the payment of the principal of, or premium, if any, or interest, if any, on any Debt Securities of such series, or in respect of a covenant or provision which cannot be modified or amended without the consent of a larger fixed percentage of holders or by the holder of each outstanding Debt Securities of the series affected.

DISCHARGE, TERMINATION AND COVENANT TERMINATION

When we establish a series of Debt Securities, we may provide that such series is subject to the termination and discharge provisions of the applicable Indenture. If those provisions are made applicable, we may elect either:

- to terminate and be discharged from all of our obligations with respect to those Debt Securities subject to some limitations; or

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- to be released from our obligations to comply with specified covenants relating to those Debt Securities, as described in the applicable prospectus supplement.

To effect that termination or covenant termination, we must irrevocably deposit in trust with the relevant Trustee an amount which, through the payment of principal and interest in accordance with their terms, will provide money sufficient to make payments on those Debt Securities and any mandatory sinking fund or similar payments on those Debt Securities. This deposit may be made in any combination of funds or government obligations. On such a termination, we will not be released from certain of our obligations that will be specified in the applicable prospectus supplement.

To establish such a trust we must deliver to the relevant Trustee an opinion of counsel to the effect that the holders of those Debt Securities:

- will not recognize income, gain or loss for U.S. federal income tax purposes as a result of the termination or covenant termination; and

- will be subject to U.S. federal income tax on the same amounts, in the same manner and at the same times as would have been the case if the termination or covenant termination had not occurred.

If we effect covenant termination with respect to any Debt Securities, the amount of deposit with the relevant Trustee must be sufficient to pay amounts due on the Debt Securities at the time of their stated maturity. However, those Debt Securities may become due and payable prior to their stated maturity if there is an Event of Default with respect to a covenant from which we have not been released. In that event, the amount on deposit may not be sufficient to pay all amounts due on the Debt Securities at the time of the acceleration.

The applicable prospectus supplement may further describe the provisions, if any, permitting termination or covenant termination, including any modifications to the provisions described above.

GOVERNING LAW

The Indentures and the Debt Securities will be governed by, and construed in accordance with, the laws of the State of New York.

REGARDING THE TRUSTEES

The Trust Indenture Act contains limitations on the rights of a trustee, should it become a creditor of ours, to obtain payment of claims in certain cases or to realize on certain property received by it in respect of any such claims, as security or otherwise. Each Trustee is permitted to engage in other transactions with us from time to time, provided that if such Trustee acquires any conflicting interest, it must eliminate such conflict upon the occurrence of an Event of Default under the relevant Indenture, or else resign.

DESCRIPTION OF CAPITAL STOCK

GENERAL

As of the date of this prospectus, we are authorized to issue up to 90,000,000 shares of stock, including up to 85,000,000 shares of common stock and up to 5,000,000 shares of preferred stock. As of March 31, 2001, we had 24,709,565 shares of common stock and no shares of preferred stock outstanding. As of that date, we also had approximately 2,153,865 shares of common stock subject to issuance upon exercise of outstanding options.

The following is a summary of the key terms and provisions of our equity securities. You should refer to the applicable provisions of our articles of incorporation, bylaws, the Texas Business Corporation Act

and the documents we have incorporated by reference for a complete statement of the terms and rights of our capital stock.

COMMON STOCK

Voting Rights. Each holder of common stock is entitled to one vote per share. Subject to the rights, if any, of the holders of any series of preferred stock pursuant to applicable law or the provision of the certificate of designation creating that series, all voting rights are vested in the holders of shares of common stock. Holders of shares of common stock have noncumulative voting rights, which means that the holders of more than 50% of the shares voting for the election of directors can elect 100% of the directors, and the holders of the remaining shares voting for the election of directors will not be able to elect any directors.

Dividends. Dividends may be paid to the holders of common stock when, as and if declared by the board of directors out of funds legally available for their payment, subject to the rights of holders of any preferred stock. Swift has never declared a cash dividend and intends to continue its policy of using retained earnings for expansion of its business.

Rights upon Liquidation. In the event of our voluntary or involuntary liquidation, dissolution or winding up, the holders of common stock will be entitled to share equally, in proportion to the number of shares of common stock held by them, in any of our assets available for distribution after the payment in full of all debts and distributions and after the holders of all series of outstanding preferred stock, if any, have received their liquidation preferences in full.

Non-Assessable. All outstanding shares of common stock are fully paid and non-assessable. Any additional common stock we offer and issue under this Prospectus will also be fully paid and non-assessable.

No Preemptive Rights. Holders of common stock are not entitled to preemptive purchase rights in future offerings of our common stock.

Listing. Our outstanding shares of common stock are listed on the New York Stock Exchange and the Pacific Stock Exchange under the symbol "SFY." Any additional common stock we issue will also be listed on the NYSE and the PSE.

PREFERRED STOCK

Our board of directors can, without approval of our shareholders, issue one or more series of preferred stock and determine the number of shares of each series and the rights, preferences and limitations of each series. The following description of the terms of the preferred stock sets forth certain general terms and provisions of our authorized preferred stock. If we offer preferred stock, a description will be filed with the SEC and the specific designations and rights will be described in a prospectus supplement, including the following terms:

- the series, the number of shares offered and the liquidation value of the preferred stock;

- the price at which the preferred stock will be issued;

- the dividend rate, the dates on which the dividends will be payable and other terms relating to the payment of dividends on the preferred stock;

- the liquidation preference of the preferred stock;

- the voting rights of the preferred stock;

- whether the preferred stock is redeemable or subject to a sinking fund, and the terms of any such redemption or sinking fund;

- whether the preferred stock is convertible or exchangeable for any other securities, and the terms of any such conversion; and

- any additional rights, preferences, qualifications, limitations and restrictions of the preferred stock.

The description of the terms of the preferred stock to be set forth in an applicable prospectus supplement will not be complete and will be subject to and qualified in its entirety by reference to the certificate of designation relating to the applicable series of preferred stock. The registration statement of which this prospectus forms a part will include the certificate of designation as an exhibit or incorporate it by reference.

Undesignated preferred stock may enable our board of directors to render more difficult or to discourage an attempt to obtain control of us by means of a tender offer, proxy contest, merger or otherwise, and to thereby protect the continuity of our management. The issuance of shares of preferred stock may adversely affect the rights of the holders of our common stock. For example, any preferred stock issued may rank prior to our common stock as to dividend rights, liquidation preference or both, may have full or limited voting rights and may be convertible into shares of common stock. As a result, the issuance of shares of preferred stock may discourage bids for our common stock or may otherwise adversely affect the market price of our common stock or any existing preferred stock.

Any preferred stock will, when issued, be fully paid and non-assessable.

ANTI-TAKEOVER PROVISIONS

Certain provisions in our articles of incorporation, bylaws and our shareholders' rights plan may encourage persons considering unsolicited tender offers or other unilateral takeover proposals to negotiate with our board of directors rather than pursue non-negotiated takeover attempts.

Our Classified Board of Directors. Our bylaws provide that our board of directors is divided into three classes as nearly equal in number as possible. The directors of each class are elected for three-year terms, and the terms of the three classes are staggered so that directors from a single class are elected at each annual meeting of stockholders. A staggered board makes it more difficult for shareholders to change the majority of the directors and instead promotes continuity of existing management.

Our Ability to Issue Preferred Stock. As discussed above, our board of directors can set the voting rights, redemption rights, conversion rights and other rights relating to authorized but unissued shares of preferred stock and could issue that stock in either private or public transactions. Preferred stock could be issued for the purpose of preventing a merger, tender offer or other takeover attempt which the board of directors opposes.

Our Rights Plan. Our board of directors has adopted a stockholders' rights plan. The rights attach to all common stock certificates representing outstanding shares. One right is issued for each share of common stock outstanding. Each right entitles the registered holder, under the circumstances described below, to purchase from us one one-thousandth of a share of our Series A Junior Participating Preferred Stock, a "Series A" share, at a price of $150.00 per one one-thousandth of a Series A share, subject to adjustment. The dividend and liquidation rights and the non-redemption feature of the Series A shares are designed so that the value of one one-thousandth of a Series A share purchasable upon exercise of each right will approximate the value of one share of common stock. The following is a summary of the terms of the rights plan. You should refer to the applicable provisions of the rights plan which we have incorporated by reference as an exhibit to the registration statement of which this prospectus is a part.

The rights will separate from the common stock and right certificates will be distributed to the holders of common stock as of the earlier of:

- 10 business days following a public announcement that a person or group of affiliated persons has acquired beneficial ownership of 15% or more of our outstanding voting shares, or

- 10 business days following the commencement or announcement of an intention to commence a tender offer or exchange offer which would result in a person or group beneficially owning 15% or more of our outstanding voting shares.

The rights are not exercisable until rights certificates are distributed. The rights will expire on July 31, 2007 unless that date is extended or the rights are earlier redeemed or exchanged.

If a person or group (with certain exceptions for investment advisers) acquires 15% or more of our voting shares, each right then outstanding, other than rights beneficially owned by such person or group, becomes a right to buy that number of shares of common stock or other securities or assets having a market value of two times the exercise price of the right. The rights belonging to the acquiring person or group become null and void.

If Swift is acquired in a merger or other business combination, or 50% of its consolidated assets or assets producing more than 50% of its earning power or cash flow are sold, each holder of a right will have the right to receive that number of shares of common stock of the acquiring company which at the time of such transaction has a market value of two times the purchase price of the right.

At any time after a person or group acquires beneficial ownership of 15% or more of our outstanding voting shares and before the earlier of the two events described in the prior paragraph or acquisition by a person or group of beneficial ownership of 50% or more of our outstanding voting shares, our board of directors may, at its option, exchange the rights, other than those owned by such person or group, in whole or in part, at an exchange ratio of one share of common stock or a fractional share of Series A stock or other preferred stock equivalent in value thereto, per right.

The Series A shares issuable upon exercise of the rights will be non-redeemable and rank junior to all other series of our preferred stock. Each whole Series A share will be entitled to receive a quarterly preferential dividend in an amount per share equal to the greater of $1.00 in cash, or in the aggregate, 1,000 times the dividend declared on the common stock, subject to adjustment. In the event of liquidation, the holders of Series A share may receive a preferential liquidation payment equal to the greater of $1,000 per share, or in the aggregate, 1,000 times the payment made on the shares of common stock. In the event of any merger, consolidation or other transaction in which the shares of common stock are exchanged for or changed into other stock or securities, cash or other property, each whole Series A share will be entitled to receive 1,000 times the amount received per share of common stock. Each whole Series A share will be entitled to 1,000 votes on all matters submitted to a vote of our stockholders and Series A shares will generally vote together as one class with the common stock and any other capital stock on all matters submitted to a vote of our stockholders.

Prior to the earlier of the date it is determined that right certificates are to be distributed or the expiration date of the rights, our board of directors may redeem all, but not less than all, of the then outstanding rights at a price of $0.01 per right. Our board of directors in its sole discretion may establish the effective date and other terms and conditions of the redemption. Upon redemption, the ability to exercise the rights will terminate and the holders of rights will only be entitled to receive the redemption price.

As long as the rights are redeemable, we may amend the rights agreement in any manner except to change the redemption price. After the rights are no longer redeemable, we may, except with respect to the redemption price, amend the rights agreement in any manner that does not adversely affect the interests of holders of the rights.

Business Combinations Under Texas Law. Swift is a Texas corporation subject to Part Thirteen of the Texas Business Corporation Act known as the

"Business Combination Law." In general, the Business Combination Law prevents an affiliated shareholder, or its affiliates or associates, from entering into a

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business combination with an issuing public corporation during the three-year period immediately following the date on which the affiliated shareholder became an affiliated shareholder, unless:

- before the date such person became an affiliated shareholder, the board of directors of the issuing public corporation approves the business combination or the acquisition of shares that caused the affiliated shareholder to become an affiliated shareholder; or

- not less than six months after the date such person became an affiliated shareholder, the business combination is approved by the affirmative vote of holders of at least two-thirds of the issuing public corporation's outstanding voting shares not beneficially owned by the affiliated shareholder, or its affiliates or associates.

An affiliated shareholder is a person that is or was within the preceding three-year period the beneficial owner of 20% or more of a corporation's outstanding voting shares. An issuing public corporation includes most publicly held Texas corporations, including Swift. The term business combination includes:

- mergers, share exchanges or conversions involving the affiliated shareholder;

- dispositions of assets involving the affiliated shareholder having an aggregate value of 10% or more of the market value of the assets or of the outstanding common stock or representing 10% or more of the earning power or net income of the corporation;

- issuances or transfers of securities by the corporation to the affiliated shareholder other than on a pro rata basis;

- plans or agreements relating to a liquidation or dissolution of the corporation involving an affiliated shareholder;

- reclassifications, recapitalizations, distributions or other transactions that would have the effect of increasing the affiliated shareholder's percentage ownership of the corporation; and

- the receipt of tax, guarantee, loan or other financial benefits by an affiliated shareholder other than proportionately as a shareholder of the corporation.

DESCRIPTION OF DEPOSITARY SHARES

We may offer preferred stock represented by depositary shares and issue depositary receipts evidencing the depositary shares. Each depositary share will represent a fraction of a share of preferred stock. Shares of preferred stock of each class or series represented by depositary shares will be deposited under a separate deposit agreement among us, a bank or trust company acting as the "Depositary" and the holders of the depositary receipts. Subject to the terms of the deposit agreement, each owner of a depositary receipt will be entitled, in proportion to the fraction of a share of preferred stock represented by the depositary shares evidenced by the depositary receipt, to all the rights and preferences of the preferred stock represented by such depositary shares. Those rights include any dividend, voting, conversion, redemption and liquidation rights. Immediately following the issuance and delivery of the preferred stock to the Depositary, we will cause the Depositary to issue the depositary receipts on our behalf.

If depositary shares are offered, the applicable prospectus supplement will describe the terms of such depositary shares, the deposit agreement and, if applicable, the depositary receipts, including the following, where applicable:

- the payment of dividends or other cash distributions to the holders of depositary receipts when such dividends or other cash distributions are made with respect to the preferred stock;

- the voting by a holder of depositary shares of the preferred stock underlying such depositary shares at any meeting called for such purpose;

- if applicable, the redemption of depositary shares upon a redemption by us of shares of preferred stock held by the Depositary;

- if applicable, the exchange of depositary shares upon an exchange by us of shares of preferred stock held by the Depositary for debt securities or common stock;

- if applicable, the conversion of the shares of preferred stock underlying the depositary shares into shares of our common stock, other shares of our preferred stock or our debt securities;

- the terms upon which the deposit agreement may be amended and terminated;

- a summary of the fees to be paid by us to the Depositary;

- the terms upon which a Depositary may resign or be removed by us; and

- any other terms of the depositary shares, the deposit agreement and the depositary receipts.

If a holder of depositary receipts surrenders the depositary receipts at the corporate trust office of the Depositary, unless the related depositary shares have previously been called for redemption, converted or exchanged into other securities of Swift, the holder will be entitled to receive at this office the number of shares of preferred stock and any money or other property represented by such depositary shares. Holders of depositary receipts will be entitled to receive whole and, to the extent provided by the applicable prospectus supplement, fractional shares of the preferred stock on the basis of the proportion of preferred stock represented by each depositary share as specified in the applicable prospectus supplement. Holders of shares of preferred stock received in exchange for depositary shares will no longer be entitled to receive depositary shares in exchange for shares of preferred stock. If the holder delivers depositary receipts evidencing a number of depositary shares that is more than the number of depositary shares representing the number of shares of preferred stock to be withdrawn, the Depositary will issue the holder a new depositary receipt evidencing such excess number of depositary shares at the same time.

Prospective purchasers of depositary shares should be aware that special tax, accounting and other considerations may be applicable to instruments such as depositary shares.

DESCRIPTION OF WARRANTS

We may issue warrants for the purchase of preferred or common stock, either independently or together with other securities. Each series of warrants will be issued under a warrant agreement to be entered into between Swift and a bank or trust company. You should refer to the warrant agreement relating to the specific warrants being offered for the complete terms of such warrant agreement and the warrants.

Each warrant will entitle the holder to purchase the number of shares of preferred or common stock at the exercise price set forth in, or calculable as set forth in any applicable prospectus supplement. The exercise price may be subject to adjustment upon the occurrence of certain events, as set forth in any applicable prospectus supplement. After the close of business on the expiration date of the warrant, unexercised warrants will become void. The place or places where, and the manner in which, warrants may be exercised shall be specified in any applicable prospectus supplement.

SELLING SHAREHOLDERS

The selling shareholders may be our directors, executive officers, employees or other holders of common stock. The selling shareholders may from time to time transfer shares to a donee, successor or other person, other than for value, and such transfers will not be made pursuant to this prospectus. Such donees, successors and other transferees also may effect sales of the shares donated, distributed or transferred pursuant to this prospectus (as supplemented or amended to reflect such transaction and donee,

distributee or transferee). The prospectus supplement for any offering of the common stock by selling shareholders will include the following information:

- the names of the selling shareholders;

- the number of shares of common stock held by each of the selling shareholders;

- the percentage of the outstanding common stock held by each of the selling shareholders; and

- the number of shares of common stock offered by each of the selling shareholders.

PLAN OF DISTRIBUTION

We and any selling shareholders may sell the securities offered by this prospectus and applicable prospectus supplements:

- through underwriters or dealers;

- through agents;

- directly to purchasers; or

- through a combination of any such methods of sale.

Any such underwriter, dealer or agent may be deemed to be an underwriter within the meaning of the Securities Act of 1933.

The applicable prospectus supplement relating to the securities will set forth:

- their offering terms, including the name or names of any underwriters, dealers or agents;

- the purchase price of the securities and the proceeds to us from such sale;

- any underwriting discounts, commissions and other items constituting compensation to underwriters, dealers or agents;

- any initial public offering price;

- any discounts or concessions allowed or reallowed or paid by underwriters or dealers to other dealers;

- in the case of debt securities, the interest rate, maturity and redemption provisions; and

- any securities exchanges on which the securities may be listed.

If underwriters or dealers are used in the sale, the securities will be acquired by the underwriters or dealers for their own account and may be resold from time to time in one or more transactions in accordance with the rules of the New York Stock Exchange and the Pacific Stock Exchange:

- at a fixed price or prices which may be changed;

- at market prices prevailing at the time of sale;

- at prices related to such prevailing market prices; or

- at negotiated prices.

The securities may be offered to the public either through underwriting syndicates represented by one or more managing underwriters or directly by one or more of such firms. Unless otherwise set forth in an applicable prospectus supplement, the obligations of underwriters or dealers to purchase the securities will be subject to certain conditions precedent and the underwriters or dealers will be obligated to purchase all the securities if any are purchased. Any public offering price and any discounts or concessions allowed or reallowed or paid by underwriters or dealers to other dealers may be changed from time to time.

Securities may be sold directly by us or through agents designated by us from time to time. Any agent involved in the offer or sale of the securities in respect of which this prospectus and a prospectus supplement is delivered will be named, and any commissions payable by us to such agent will be set forth, in the prospectus supplement. Unless otherwise indicated in the prospectus supplement, any such agent will be acting on a best efforts basis for the period of its appointment.

If so indicated in the prospectus supplement, we will authorize underwriters, dealers or agents to solicit offers from certain specified institutions to purchase securities from us at the public offering price set forth in the prospectus supplement pursuant to delayed delivery contracts providing for payment and delivery on a specified date in the future. Such contracts will be subject to any conditions set forth in the prospectus supplement and the prospectus supplement will set forth the commission payable for solicitation of such contracts. The underwriters and other persons soliciting such contracts will have no responsibility for the validity or performance of any such contracts.

Underwriters, dealers and agents may be entitled under agreements entered into with us to be indemnified by us against certain civil liabilities, including liabilities under the Securities Act of 1933, or to contribution by Swift to payments which they may be required to make. The terms and conditions of such indemnification will be described in an applicable prospectus supplement. Underwriters, dealers and agents may be customers of, engage in transactions with, or perform services for, us in the ordinary course of business.

Each class or series of securities will be a new issue of securities with no established trading market, other than the common stock, which is listed on the New York Stock Exchange and the Pacific Stock Exchange. We may elect to list any other class or series of securities on any exchange, other than the common stock, but we are not obligated to do so. Any underwriters to whom securities are sold by us for public offering and sale may make a market in such securities, but such underwriters will not be obligated to do so and may discontinue any market making at any time without notice. No assurance can be given as to the liquidity of the trading market for any securities.

Certain persons participating in any offering of securities may engage in transactions that stabilize, maintain or otherwise affect the price of the securities offered. In connection with any such offering, the underwriters or agents, as the case may be, may purchase and sell securities in the open market. These transactions may include overallotment and stabilizing transactions and purchases to cover syndicate short positions created in connection with the offering. Stabilizing transactions consist of certain bids or purchases for the purpose of preventing or retarding a decline in the market price of the securities; and syndicate short positions involve the sale by the underwriters or agents, as the case may be, of a greater number of securities than they are required to purchase from us, as the case may be, in the offering. The underwriters may also impose a penalty bid, whereby selling concessions allowed to syndicate members or other broker-dealers for the securities sold for their account may be reclaimed by the syndicate if such securities are repurchased by the syndicate in stabilizing or covering transactions. These activities may stabilize, maintain or otherwise affect the market price of the securities, which may be higher than the price that might otherwise prevail in the open market, and if commenced, may be discontinued at any time. These transactions may be effected on the New York Stock Exchange, the Pacific Stock Exchange, in the over-the-counter market or otherwise. These activities will be described in more detail in the sections entitled "Plan of Distribution" or "Underwriting" in the applicable prospectus supplement.

LEGAL OPINIONS

Jenkens & Gilchrist, A Professional Corporation, Houston, Texas, will issue an opinion for Swift regarding the legality of the securities offered by this prospectus and applicable prospectus supplement. If the securities are being distributed in an underwritten offering, certain legal matters will be passed upon for the underwriters by counsel identified in the applicable prospectus supplement.

EXPERTS

The audited financial statements incorporated by reference in this prospectus and elsewhere in the registration statement have been audited by Arthur Andersen LLP, independent public accountants, as indicated in their report with respect thereto, and is incorporated herein in reliance upon the authority of said firm as experts in giving said report.

Information referenced or incorporated by reference in this prospectus regarding our estimated quantities of oil and gas reserves and the discounted present value of future net cash flows therefrom is based upon estimates of such reserves and present values audited by H.J. Gruy and Associates, Inc., independent petroleum engineers.

[SWIFT LOGO]