SWIFT ENERGY CO
Form 424B5
April 12, 2002

FILED PURSUANT TO RULE 424(b)(5)
REGISTRATION NO. 333-64692

$200,000,000

[SWIFT LOGO]

9 3/8% Senior Subordinated Notes Due 2012

We will pay interest on the notes on each May 1 and November 1. The first interest payment will be made on November 1, 2002. There is no sinking fund for the notes.

We may redeem the notes on and after May 1, 2007 at the prices listed on page S-53. Prior to May 1, 2005, we may redeem up to 33 1/3% of the notes at a price of 109.375% with the proceeds of qualified offerings of our equity.

The notes will be unsecured senior subordinated obligations and will be subordinated in right of payment to all our existing and future senior debt, including our bank debt.

INVESTING IN THE NOTES INVOLVES RISKS. SEE "RISK FACTORS" BEGINNING ON PAGE S-11 OF THIS PROSPECTUS SUPPLEMENT AND ON PAGE 2 OF THE ACCOMPANYING PROSPECTUS.

	PRICE TO PUBLIC(1)	UNDERWRITING DISCOUNTS AND COMMISSIONS	PROCEEDS TO SWIFT ENERGY COMPANY(1)
Per Note.......................................	100%	2.5%	97.5%
Total..	$200,000,000	$5,000,000	$195,000,000

(1) Plus accrued interest, if any, from April 16, 2002

Delivery of the notes, in book-entry form only, will be made on or about April 16, 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

BANC ONE CAPITAL MARKETS, INC.
CIBC WORLD MARKETS
A.G. EDWARDS & SONS, INC.
FRIEDMAN BILLINGS RAMSEY
JEFFERIES & COMPANY, INC.
JPMORGAN
MORGAN STANLEY
UBS WARBURG

The date of this prospectus supplement is April 11, 2002

[INSIDER FRONT COVER]

PICTURE

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

IF THE DESCRIPTION OF THE NOTES VARIES BETWEEN THIS PROSPECTUS SUPPLEMENT AND THE ACCOMPANYING PROSPECTUS, YOU SHOULD RELY ON THE INFORMATION IN THIS PROSPECTUS SUPPLEMENT.

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 NOTES 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-100 for explanations of abbreviations and terms used in this prospectus supplement.

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PROSPECTUS SUPPLEMENT

PROSPECTUS

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.

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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 the notes and their terms 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.

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:

		PRO FORMA PROVED RESERVES AS OF YEAR END 2001	
AREA	LOCATION	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 prospectus supplement dated April 9, 2002 with the SEC relating to the offer and sale of 1,500,000 shares of our common stock with an over-allotment option, which has been exercised in full, of 225,000 additional shares of common stock. This stock was offered in a separate public offering which is expected to close April 12, 2002. The net proceeds of the common stock offering are estimated to be approximately $30.5 million, which will be used to reduce a portion of the outstanding indebtedness under our credit facility incurred in connection with our current acquisitions, development and exploitation activities. This notes offering and the offering of common stock are not conditioned upon each other.

On April 8, 2002, Moody's Investors Service announced it had assigned a B3 rating to this 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 1/4% senior subordinated notes due 2009 to B3, down from B2. On April 10, 2002, Standard & Poor's announced it had assigned a B rating to this notes offering. In connection with this rating, Standard & Poor's announced further that it had reaffirmed its existing B rating on our 10 1/4% senior subordinated notes due 2009.

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.

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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 our common stock offering and this offering, as of December 31, 2001, our long-term debt would have comprised approximately 49% of our total capitalization. As of March 31, 2002, after the TAWN acquisition in January 2002 and the Antrim acquisition in March 2002, and after giving effect to our common stock offering and this offering, our long-term debt would have comprised approximately 49% of our total capitalization. Additionally, after applying the net proceeds from our common stock offering and this offering to reduce amounts outstanding under our credit facility, based on our March 31, 2002 balance, we expect to have approximately $188.9 million of available borrowing capacity. By replacing indebtedness incurred under our revolving credit facility in connection with acquisition, development and exploitation activity with the net proceeds from our common stock offering and this offering, we will be implementing our strategy of matching long-lived assets with long-term debt and equity.

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THE OFFERING

Issuer........................	Swift Energy Company
Securities Offered............	$200.0 million aggregate principal amount of 9 3/8% senior subordinated notes due 2012.
Maturity Date.................	May 1, 2012.

Interest Payment Dates........	May 1 and November 1 of each year, commencing on November 1, 2002.
Ranking.......................	The notes: - are unsecured senior subordinated obligations; - are subordinate in right of payment to all existing and future senior debt, including our bank debt; - rank equally with our senior subordinated notes due 2009 and any future senior subordinated debt; and - are senior to any future junior subordinated debt.
Subsidiary Guaranty...........	If certain of our subsidiaries incur debt, issue preferred stock or guarantee any of our other debt, that subsidiary generally will be required to guarantee the notes. As of the date of this prospectus supplement, there are no subsidiary guarantors. The guarantee of any subsidiary will be subordinated in right of payment to the senior debt of the subsidiary guarantor and senior in right of payment to any junior subordinated debt of the subsidiary guarantor.
Optional Redemption...........	On or after May 1, 2007, we may redeem some or all of the notes at any time at the prices listed under the heading "Description of the Notes -- Optional Redemption." Before May 1, 2005, we may redeem up to 33 1/3% of the aggregate principal amount of the notes originally issued with the proceeds from qualified offerings of our equity at a price equal to 109.375% of the principal amount of the redeemed notes, plus accrued interest to the redemption date, provided that at least 66 2/3% of the aggregate principal amount of the notes originally issued remains outstanding.
Change of Control Offer.......	If a change in control of Swift occurs, we must offer to repurchase the notes at a purchase price of 101% of their face amount, plus accrued interest to the date we repurchase the notes.
Certain Covenants.............	We will issue the notes under an indenture containing covenants for your benefit. These covenants restrict our ability and the ability of our subsidiaries to: - incur additional debt or issue preferred stock; - create liens;

- pay dividends or make other restricted payments;
- issue and sell capital stock of our restricted subsidiaries;
- transfer or sell assets;

- enter into transactions with affiliates;
- consolidate, merge or transfer all or substantially all of our assets;
- incur dividend or other payment restrictions affecting subsidiaries; or
- make investments.

These covenants are subject to important exceptions and qualifications, which are described in "Description of the Notes -- Certain Covenants."

Use of Proceeds............... The net proceeds from this offering are estimated to be approximately $194.5 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 exploitation activities.

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-11 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
Ratio of earnings to fixed charges(e)	--	5.2x	2.4x	
Ratio of EBITDA to cash interest(d)(f)	7.4x	7.6x	6.6x	
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 1/4% convertible subordinated notes	--	--	115,000	1
10 1/4% senior subordinated notes	124,197	124,129	124,068	
Stockholders' equity	312,653	332,154	170,404	1

(Notes on following page)

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 and ability to incur and service debt. 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 and debt servicing ability 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. The definition of EBITDA stated herein differs from the definition of EBITDA applicable to the covenants for the notes, in that the notes definition makes certain exclusions to net income, some of which would reduce EBITDA. See "Description of the Notes -- Certain Definitions -- Consolidated Net Income" and "-- EBITDA."

(e) For purposes of calculating the ratio of earnings to fixed charges, fixed charges include interest expense, capitalized interest, amortization of debt issuance costs and that portion of non-capitalized rental expense deemed to be the equivalent of interest. Earnings represents income before income taxes from continuing operations before fixed charges. Due to the $98.9 million and $90.8 million non-cash charges incurred in 2001 and 1998, respectively, resulting from a write-down in the carrying value of natural gas and oil properties, 2001 and 1998 earnings were insufficient by $40.2 million and $76.9 million to cover fixed charges in 2001 and 1998, respectively. If these non-cash charges were excluded, the ratio of earnings to fixed charges would have been 4.1x for 2001 and 2.1x for 1998.

(f) Cash interest is defined as the total amount of interest paid on our obligations, prior to any allowed capitalized amount.

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

(Notes on following page)

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 notes involves significant risks. You should carefully consider the following risk factors before you decide to purchase the notes. 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 the notes.

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 March 31, 2002, after the TAWN acquisition in January 2002 and the Antrim acquisition in March 2002, and after giving effect to our common stock offering and this offering, our long-term debt would have comprised approximately 49% 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 March 31, 2002, we had a $300.0 million credit facility with a borrowing base of $275.0 million of which $44.0 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.

YOUR RIGHT TO RECEIVE PAYMENTS ON THE NOTES IS JUNIOR TO OUR EXISTING SENIOR INDEBTEDNESS.

The indebtedness evidenced by the notes will be senior subordinated obligations of Swift. The payment of the principal of, premium on, if any, and interest on the notes is subordinate in right of payment to the prior payment in full of all senior indebtedness of Swift.

Based upon our outstanding indebtedness at March 31, 2002, after the TAWN acquisition in January 2002 and the Antrim acquisition in March 2002, and after giving effect to our common stock offering and this offering, we expect to have approximately $6.1 million in senior indebtedness outstanding. Any future borrowings under our bank credit facility will also constitute senior indebtedness. Although the indenture contains limitations on the amount of additional indebtedness that we may incur, the amount of such indebtedness could be substantial and senior to the notes. See "Description of the Notes -- Certain Covenants -- Limitation on Indebtedness."

IF WE EXPERIENCE A CHANGE OF CONTROL, WE MAY BE UNABLE TO REPURCHASE THE NOTES AS REQUIRED UNDER THE INDENTURE.

In the event of a change of control, you will have the right to require us, subject to various conditions, to repurchase the notes. We may not have sufficient financial resources to pay the repurchase price for the notes, or may be prohibited from doing so under our credit facility or other debt agreements. In addition, before we can purchase any notes, we may be required to:

- repay our bank debt or other debt that ranks senior to the notes; or

- obtain a consent from lenders of senior debt to repurchase the notes.

If a change of control occurs and we are prohibited from repurchasing the notes, our failure to do so would cause us to default under the indenture, which in turn is likely to be a default under our credit facility, our outstanding senior subordinated notes due 2009 and any future debt. Any other default under our credit facility or other debt would also likely prohibit our repurchasing the notes.

THE NOTES HAVE NO EXISTING MARKET, AND A MARKET MAY NOT DEVELOP.

There is no existing market for the notes, and we are not applying to list the notes on any securities exchange. Therefore, no liquid market may exist for the notes at any time, which may depress the prices at which you will be able to sell your notes.

FRAUDULENT CONVEYANCE CONSIDERATIONS COULD AVOID GUARANTEES FOR THE NOTES.

In the future, some of our subsidiaries might guarantee our obligations under the notes on an unsecured senior subordinated basis. Under fraudulent conveyance laws, a court might subordinate or avoid any guarantees of the notes by our subsidiaries in favor of a subsidiary's other debts or liabilities. To the extent a subsidiary's guarantee of the notes is avoided as a result of fraudulent conveyance laws or held unenforceable for any other reason, you would receive no payments under that subsidiary's guarantee and would be creditors solely of us and any subsidiaries whose guarantees were not avoided.

USE OF PROCEEDS

We estimate that the net proceeds from the sale of the notes will be approximately $194.5 million. We intend to use the net proceeds to repay a large 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 $200.0 million to $275.0 million. At March 31, 2002, $231.0 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 this offering. Our bank credit facility is described in more detail in the "Description of Existing Indebtedness" section of this prospectus supplement.

CAPITALIZATION

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

- our historical capitalization;
- our capitalization as adjusted for the estimated net proceeds of $30.5 million from the sale of our common stock; and
- our capitalization as further adjusted for the estimated net proceeds of $194.5 million from this offering.

This notes offering and our offering of common stock are not conditioned upon each other. This table does not reflect the TAWN acquisition or 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	$ 93,083
Long-term debt			
Bank borrowings(a)	134,000	103,516	--
10 1/4% Senior Subordinated Notes due 2009	124,197	124,197	124,197
9 3/8% Senior Subordinated Notes due 2012	--	--	200,000
Total long-term debt	$258,197	$227,713	$324,197
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 27,359,598 shares issued and 24,795,564 and 26,520,564 shares outstanding, respectively, as adjusted for the common stock offering	257	274	274
Additional paid-in capital	296,173	326,640	326,640
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	343,137	343,137
Total capitalization	$570,850	$570,850	$667,334

(a) As of March 31, 2002, our outstanding bank borrowings were $231.0 million. Accordingly, after repaying a portion of amounts outstanding with the net proceeds from the common stock offering, our bank borrowings as of March 31, 2002 would have been approximately $200.5 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 common stock offering and net proceeds expected from this offering, these amounts would have been approximately $6.1 million and $2.1 million, respectively.

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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
Ratio of earnings to fixed charges(e)......................	--	5.2x	2.4x	
Ratio of EBITDA to cash interest(d)(f).....................	7.4x	7.6x	6.6x	
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 1/4% convertible subordinated notes....................	--	--	115,000	1
10 1/4% senior subordinated notes........................	124,197	124,129	124,068	
Stockholders' equity.......................................	312,653	332,154	170,404	1

Notes on following page)

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 and ability to incur and service debt. 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 and debt servicing ability 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. The definition of EBITDA stated herein differs from the definition of EBITDA applicable to the covenants for the notes, in that the notes definition makes certain exclusions to net income, some of which would reduce EBITDA. See "Description of the Notes -- Certain Definitions -- Consolidated Net Income" and "-- EBITDA."

(e) For purposes of calculating the ratio of earnings to fixed charges, fixed charges include interest expense, capitalized interest, amortization of debt issuance costs and that portion of non-capitalized rental expense deemed to be the equivalent of interest. Earnings represents income before income taxes from continuing operations before fixed charges. Due to the $98.9 million and $90.8 million non-cash charges incurred in 2001 and 1998, respectively, resulting from a write-down in the carrying value of natural gas and oil properties, 2001 and 1998 earnings were insufficient by $40.2 million and $76.9 million to cover fixed charges in 2001 and 1998, respectively. If these non-cash charges were excluded, the ratio of earnings to fixed charges would have been 4.1x for 2001 and 2.1x for 1998.

(f) Cash interest is defined as the total amount of interest paid on our obligations, prior to any allowed capitalized amount.

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

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 our common stock offering and this offering, as of December 31, 2001, our long-term debt would have comprised approximately 49% of our total capitalization. As of March 31, 2002, after the TAWN acquisition in January 2002 and the Antrim acquisition in March 2002, and after giving effect to our common stock offering and this offering, our long-term debt would have comprised approximately 49% of our total capitalization. Additionally, after applying the net proceeds from our common stock offering and this offering to reduce amounts outstanding under our credit facility, based on our March 31, 2002 balance, we expect to have approximately $188.9 million of available borrowing capacity. By replacing indebtedness incurred under our revolving credit facility in connection with acquisition, development and exploitation activity with the net proceeds from our common stock offering and this 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 con