SWIFT ENERGY CO
Form 424B2
June 09, 2004

Filed Pursuant to Rule 424(b)(2)
Registration No. 333-112041

SUBJECT TO COMPLETION, DATED JUNE 9, 2004

PRELIMINARY PROSPECTUS SUPPLEMENT TO PROSPECTUS DATED MAY 11, 2004

$150,000,000

% Senior Notes Due 2011

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

Prior to , 2007, we may redeem up to 35% of the notes using proceeds from public offerings of our equity. We may redeem all of the notes prior to , 2008 at a price equal to 100% of the principal amount plus the applicable premium set forth in this prospectus supplement. In addition, we may redeem some or all of the notes after , 2008 at the redemption prices listed on page S- .

Investing in the notes involves risks. See Risk Factors beginning on page S-11 of this prospectus supplement and on page 3 of the accompanying prospectus.

	Price to Public(1)	Underwriting Discounts and Commissions	Proceeds to Swift Energy Company(1)
Per Note	%	%	%
Total	$	$	$

(1) Plus accrued interest, if any, from , 2004.

Delivery of the notes, in book-entry form only, will be made on or about , 2004.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of 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

Goldman, Sachs & Co.

Jefferies & Company, Inc.

Banc One Capital Markets, Inc.

Deutsche Bank Securities

CIBC World Markets

BNP PARIBAS

The date of this prospectus supplement is , 2004

[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.

We expect that delivery of the notes will be made against payment therefor on or about , 2004, which will be the tenth business day following the date of pricing of the notes (such settlement code being herein referred to as T+10). You should recognize that trading of the notes on the date of pricing and the next seven succeeding business days may be affected by the T+10 settlement. See Underwriting.

See the Glossary of Terms beginning on page S-99 for explanations of abbreviations and terms used in this prospectus supplement.

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INCORPORATION OF ADDITIONAL DOCUMENTS BY REFERENCE

In addition to the documents referred to under Where You Can Find More Information in the accompanying prospectus, this prospectus supplement incorporates by reference our Annual Report on Form 10-K for the fiscal year ended December 31, 2003 and our Quarterly Report on Form 10-Q for the three months ended March 31, 2004 filed by us with the Securities and Exchange Commission.

SUMMARY

This summary highlights selected information from this prospectus supplement and the accompanying prospectus, but may not contain all of the information that is important to you. This prospectus supplement and the accompanying prospectus include specifics of the offering of 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 both, and the documents we incorporate by reference.

About Swift

We are engaged in developing, exploring, acquiring, and operating oil and gas properties, with a focus on oil and natural gas reserves onshore and in the inland waters of Louisiana and Texas and onshore New Zealand. We were founded in 1979 and are headquartered in Houston, Texas. At year-end 2003, we had estimated proved reserves of 820.4 Bcfe with a PV-10 Value of over $1.5 billion. As of December 31, 2003, we had interests in 998 wells and operated 870 of these wells representing 95% of our proved reserves. Based on our 2003 year-end proved reserves and 2003 production, we calculated our average reserve life as 15.4 years.

We currently focus primarily on development and exploration in four domestic core areas and two core areas in New Zealand. The following table sets forth information regarding our proved reserves and production in our core areas:

Area	Location	% of Year-End 2003 Proved Reserves	% of 2003 Production
AWP Olmos	South Texas	26%	16%
Brookeland	East Texas	5%	7%
Lake Washington	South Louisiana	32%	23%
Masters Creek	Central Louisiana	8%	11%
Rimu/ Kauri	New Zealand	15%	6%
TAWN	New Zealand	6%	30%
% of Total		92%	93%

We have a well-balanced portfolio of oil and gas properties and prospects. Our proved reserves at year-end 2003 were comprised of approximately 47% crude oil, 41% natural gas, and 12% NGLs, of which 59% were proved developed. Our proved reserves are concentrated 40% in Louisiana, 37% in Texas, and 21% in New Zealand. The AWP Olmos and Lake Washington areas and Rimu/ Kauri area in New Zealand are characterized by long-lived reserves that we expect to be steadily produced over a long period of time. The TAWN fields are a mix of both long-lived and shorter-lived reserves. The Masters Creek and Brookeland areas are characterized by shorter-lived reserves with high initial rates of production. We believe these shorter-lived reserves complement our long-lived reserves.

Competitive Strengths and Business Strategy

We believe that our competitive strengths, together with a balanced and comprehensive business strategy, provide us with the flexibility and capability to accomplish our goals. Our primary goals for the next five years are to increase our proved oil and natural gas reserves at an average rate of 5% to 10% per year and to increase our production at an average rate of 7% to 12% per year.

Demonstrated Ability to Grow Reserves and Production

We have grown our proved reserves from 436.1 Bcfe to 820.4 Bcfe over the five-year period ended December 31, 2003. Over the same period, our annual production has grown from 39.0 Bcfe to 53.2 Bcfe and our annual net cash provided by operations has increased from $54.2 million to $110.8 million. Our growth in reserves and production has resulted primarily from drilling activities in our six core areas combined with producing property acquisitions. We believe that we have the opportunities, experience, and knowledge to continue growing our reserves and production.

Balanced Approach to Growth

Our strategy is to increase our reserves and production through both drilling and acquisitions, shifting the balance between the two activities in response to market conditions. In general, we focus on drilling in our core property and emerging growth areas when oil and gas prices are strong. When prices weaken and the per unit cost of acquisitions becomes more attractive, we shift our focus toward acquisitions. We believe this balanced approach has resulted in our ability to grow in a strategically cost effective manner. Over the five-year period ended December 31, 2003, we replaced 266% of our production at an average cost of $1.25 per Mcfe. In 2004, we believe we are positioned to grow our proved reserves 5% to 8% and our production 11% to 17%.

Concentrated Focus on Core Areas with Operational Control

The concentration of our operations in six core areas allows us to realize economies of scale in drilling and production by enabling us to manage larger producing fields with less personnel while minimizing incremental costs of increased drilling and completions. Our average lease operating costs, excluding taxes, were $0.64, $0.60, and $0.56 per Mcfe in 2003, 2002, and 2001, respectively. The value of this concentration is enhanced by our operating 95% of our proved oil and natural gas reserve base as of December 31, 2003. Retaining operational control allows us to more effectively manage production, control operating costs, allocate capital, and time field development.

Develop Under-Exploited Properties

We are focused on applying modern technologies and recovery methods to areas with known hydrocarbon resources. For example, the Lake Washington field was discovered in the 1930s. We acquired our properties in this area for $30.5 million in 2001. Since that time, we have increased our average daily production from less than 700 BOE to over 9,300 BOE for the quarter ended March 31, 2004. We have also increased our proved reserves in the area from 7.7 million BOE, or 46.2 Bcfe, to approximately 43.5 million BOE, or 261.0 Bcfe, as of December 31, 2003. We intend to continue acquiring large acreage positions in under-explored and under-exploited areas, where we can apply modern technologies to grow production as we develop these fields.

Capitalize on the Near Term Depletion of New Zealand s Largest Gas Field

The Maui field in New Zealand currently supplies over 70% of the natural gas produced in New Zealand. The Maui field is expected to be depleted by 2007, which has caused significant upward pressure on prices for natural gas in the country. Our average natural gas price in New Zealand has increased 40% from the first quarter of 2003 to the first quarter of 2004. We expect the prices we receive for our natural gas in New Zealand to continue to increase in the foreseeable future. Our New Zealand activities provide us with long term growth opportunities and significant upside potential in a country with stable political and economic conditions, existing oil and gas infrastructure, and favorable tax and royalty regimes.

Maintain Financial Flexibility and a Conservative Capital Structure

We practice a disciplined approach to financial management and have historically maintained a strong capital structure to provide us with the ability to execute our business plan. As of March 31, 2004, our debt to capitalization was approximately 46% and our debt to proved reserves was $0.44 per Mcfe. We plan to maintain a conservative capital structure and financial flexibility through the prudent use of capital and an active hedging program. The combination of hedging with collars and floors and the sale of our New Zealand natural gas production under long term, fixed price contracts provides for a more stable cash flow.

The Offering

Issuer	Swift Energy Company
Securities Offered	$150.0 million aggregate principal amount of % senior notes due 2011.
Maturity Date	, 2011.
Interest Payment Dates	and of each year, commencing on .
Ranking	The notes: are senior unsecured obligations; will rank equally with all our existing and future senior unsecured indebtedness; will be effectively subordinated to all of our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including indebtedness under our bank credit facility, and to all liabilities of our subsidiaries that are not subsidiary guarantors; and will rank senior to all of our existing and future subordinated indebtedness.
Subsidiary Guaranty	If any of our domestic subsidiaries incurs debt, issues preferred stock, or guarantees any of our other debt, that subsidiary may be required to guarantee the notes. As of the date of this prospectus supplement, there are no subsidiary guarantors.
Optional Redemption	Prior to , 2007, we may redeem up to 35% of the principal amount of the notes originally issued with the proceeds from public offerings of our equity at a price equal to % of the principal amount, plus accrued interest to the redemption date, provided that at least 65% of the aggregate principal amount of the notes originally issued remains outstanding. Prior to , 2008, we may redeem all of the notes at a price equal to 100% of the principal amount, plus the applicable premium set forth in this prospectus supplement and accrued interest to the redemption date. On or after , 2008, we may redeem some or all of the notes at any time at the prices listed in this prospectus supplement, plus accrued interest to the redemption date.
Change of Control Offer	If we experience a change in control, we must offer to repurchase the notes at a purchase price of 101% of the principal 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;

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

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

The indenture allows suspension of many of the covenants discussed above if in the future the notes are rated investment grade by both Moody s and S&P and no default or event of default has occurred and is continuing under the indenture. See Description of the Notes Covenant Suspension.

Use of Proceeds	We will receive net proceeds from this offering of approximately $146.0 million. We intend to use approximately $131.4 million of the net proceeds to repurchase our 10 1/4% senior subordinated notes due 2009 and the remainder to repay indebtedness under our bank credit facility and for general corporate purposes.

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 3 of the accompanying prospectus.

Summary Consolidated Financial Data

The summary consolidated financial data presented below as of and for each of the five years ended December 31, 2003 has been derived from our audited consolidated financial statements. The summary consolidated financial data as of and for each of the three months ended March 31, 2004 and 2003 has been derived from our unaudited consolidated financial statements. For a discussion of our significant financial results and conditions during 2003, 2002, and 2001 and during the three month periods ended March 31, 2004 and 2003, see Management s Discussion and Analysis of Financial Condition and Results of Operations in this prospectus supplement.

	Three Months Ended March 31,		Year Ended December 31,				
	2004	**2003**	**2003**	**2002**	**2001**	**2000**	**1999**
			(In thousands, except ratios)				
Income Statement Data:							
Revenues:							
Oil and gas sales	$ 65,954	$ 54,850	$211,033	$141,196	$181,185	$189,139	$108,899
Gain on asset disposition				7,333			
Price risk management and other, net	(598)	(1,350)	(2,132)	1,441	2,622	2,486	1,772
Total revenues	65,356	53,500	208,901	149,970	183,807	191,625	110,671
Costs and expenses:							
General and administrative, net of reimbursement	4,030	3,557	14,097	10,565	8,187	5,586	4,497
Depreciation, depletion, and amortization	18,296	14,912	63,072	56,224	59,502	47,771	42,349
Accretion of asset retirement obligation	170	215	857				
Lease operating costs	9,626	7,313	33,833	29,656	24,990	19,227	13,736
Severance and other taxes	6,247	4,594	19,034	11,841	11,730	9,993	5,910
Interest expense, net	6,901	6,685	27,269	23,275	12,627	15,968	14,443
Other expenses					2,102	984	
Write-down of oil and gas properties(1)					98,862		
Total costs and expenses	45,270	37,276	158,162	131,562	218,000	99,530	80,935
Income (loss) before income taxes and change in accounting principle	20,086	16,224	50,739	18,408	(34,193)	92,095	29,736
Provision (benefit) for income taxes	5,498	5,739	16,469	6,485	(12,238)	32,911	10,450
Income (loss) before change in accounting principle	14,588	10,485	34,271	11,923	(21,955)	59,184	19,286
Cumulative effect of change in accounting principle (net of taxes)(2)		4,377	4,377		393		
Net income (loss)	$ 14,588	$ 6,108	$ 29,894	$ 11,923	$ (22,348)	$ 59,184	$ 19,286
Other Financial Data:							
EBITDA(3)	$ 45,454	$ 38,036	$141,937	$ 90,575	$136,799	$155,835	$ 86,528
Net cash provided by operating activities	39,596	26,799	110,827	71,626	139,884	128,197	73,603

Capital expenditures	45,150	26,335	144,503	155,234	275,126	173,277	78,113
Ratio of earnings to fixed charges(4)	3.2x	2.7x	2.3x	1.4x		5.2x	2.4x
Ratio of EBITDA to cash interest(3)(5)	6.6x	5.7x	4.3x	3.5x	7.4x	7.5x	6.6x
Balance Sheet Data (at end of period):							
Working capital (deficit)	$ (15,370)	$ (5,247)	$ (35,099)	$ (17,116)	$ (36,492)	$ (22,452)	$ 16,535
Total assets	886,369	786,549	859,839	767,006	671,683	572,387	454,299
Long term debt:							
Bank borrowings	32,500	5,700	15,900		134,000	10,600	
6 1/4% convertible subordinated notes							115,000
10 1/4% senior subordinated notes	124,377	124,292	124,355	124,272	124,197	124,129	124,068
9 3/8% senior subordinated notes	200,000	200,000	200,000	200,000			
Stockholders equity	413,827	371,856	397,391	365,073	312,653	332,154	170,404

(1) Due primarily to a decline in prices for both oil and gas in the fourth quarter of 2001, a pre-tax domestic full cost ceiling write-down of oil and gas properties of $98.9 million, or $63.5 million after-tax, was necessary at December 31, 2001.

(2) We adopted SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, effective January 1, 2001 resulting in a one-time net of taxes charge of $0.4 million in the first quarter of 2001, which is recorded as a cumulative effect of change in accounting principle. We adopted SFAS No. 143, Accounting for Asset Retirement Obligations, effective January 1, 2003. Our adoption of SFAS No. 143 resulted in a one-time net of taxes charge of $4.4 million in the first quarter of 2003, which is recorded as a cumulative effect of change in accounting principle.

(3) EBITDA represents income before interest expense, income tax, depreciation, depletion, and amortization, write-down of oil and gas properties, accretion of asset retirement obligation, and gain on asset disposition. 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. 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.

EBITDA is not intended to represent net income as defined by GAAP and such information should not be considered as an alternative to net income, cash flow from operations or any other measure of performance prescribed by GAAP in the United States. The following table reconciles net income to EBITDA for the periods presented:

	Three Months Ended March 31,		**Year Ended December 31,**				
	2004	**2003**	**2003**	**2002**	**2001**	**2000**	**1999**
				(In thousands)			
Net income (loss)	$14,588	$ 6,108	$ 29,894	$11,923	$ (22,348)	$ 59,184	$19,286
Provision (benefit) for income taxes	5,498	5,739	16,469	6,485	(12,238)	32,911	10,450
Cumulative effect of change in accounting principle (net of taxes)		4,377	4,377		393		
Interest expense, net	6,901	6,685	27,269	23,275	12,627	15,968	14,443
Depreciation, depletion, and amortization, and accretion of asset retirement obligation	18,466	15,127	63,929	56,224	59,502	47,771	42,349
Gain on asset disposition				(7,333)			
Write-down of oil and gas properties					98,862		
EBITDA	$45,454	$38,036	$141,937	$90,575	$136,799	$155,835	$86,528

(4) 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 charge incurred in 2001 resulting from a write-down in the carrying value of natural gas and oil properties, 2001 earnings were insufficient by $40.2 million to cover fixed charges in 2001. If this non-cash charge was excluded, the ratio of earnings to fixed charges would have been 4.1x for 2001.

(5) Cash interest is the total amount of interest paid on our obligations, including capitalized amounts.

Summary Reserves and Production Data

The following tables set forth certain summary information with respect to estimates of our proved oil and natural gas reserves, and additional production and operating data as of and for the periods presented. Our proved reserve estimates were audited by H.J. Gruy and Associates, Inc., independent petroleum consultants. Gruy s audit included examination, on a test basis, of the evidence supporting our reserves and was based upon review of production histories and other geological, economic, and engineering data provided by us. See Business and Properties Oil and Natural Gas Reserves and Risk Factors.

	As of and for the Year Ended December 31,				
	2003	2002	2001	2000	1999
Estimated proved oil and natural gas reserves:					
Natural gas reserves (MMcf):					
Proved developed	210,120	233,515	181,652	215,170	174,046
Proved undeveloped	125,685	93,217	143,260	203,444	155,914
Total	335,805	326,732	324,912	418,614	329,960
Oil reserves (MBbls):					
Proved developed	45,525	35,928	23,760	10,980	8,437
Proved undeveloped	35,235	34,511	29,723	24,154	12,369
Total	80,760	70,439	53,483	35,134	20,806
Total proved oil and natural gas reserves (MMcfe)	820,364	749,365	645,808	629,416	454,797
Estimated present value of proved reserves (in thousands):					
Proved developed	$ 940,883	$ 679,356	$344,479	$1,257,571	$301,200
Proved undeveloped	597,912	481,833	258,507	1,055,684	262,855
PV-10 Value	$1,538,795	$1,161,189	$602,986	$2,313,255	$564,055
Standardized measure of discounted estimated future net cash flows after income taxes	$1,134,857	$ 836,870	$454,558	$1,577,958	$438,944
Prices used in calculating end of year proved reserves(1)**:**					
Oil (per Bbl)	$ 30.16	$ 29.27	$ 18.45	$ 24.62	$ 23.69
Natural gas (per Mcf)	$ 4.56	$ 3.49	$ 2.51	$ 9.86	$ 2.58
Other reserves data:					
Three-year reserve replacement cost (per Mcfe)(2)	$ 1.51	$ 1.27	$ 1.42	$ 1.07	$ 1.17
Three-year reserve replacement rate(3)	229%	316%	263%	319%	287%
Natural gas as percent of total proved reserve quantities	41%	44%	50%	67%	73%
Proved developed reserves as percent of total proved reserves	59%	60%	50%	45%	49%

	Three Months Ended March 31,	Year Ended December 31,

	2004	2003	2003	2002	2001	2000	1999
Net sales volume:							
Oil (MBbls)	1,402	863	4,193	3,770	3,055	2,472	2,565
Natural gas (MMcf)(4)	5,873	7,684	28,003	27,132	26,459	27,525	27,485
Total production (MMcfe)(4)(5)	14,286	12,862	53,158	49,752	44,791	42,357	42,874
Weighted average sales prices:							
Oil (per Bbl)	$ 31.80	$ 30.55	$ 27.47	$ 20.88	$ 22.64	$ 29.35	$ 16.75
Natural gas (per Mcf)	$ 3.64	$ 3.71	$ 3.42	$ 2.30	$ 4.23	$ 4.24	$ 2.40
Selected data (per Mcfe):							
Lease operating costs	$ 0.67	$ 0.57	$ 0.64	$ 0.60	$ 0.56	$ 0.45	$ 0.32
Severance and other taxes	$ 0.44	$ 0.36	$ 0.36	$ 0.24	$ 0.26	$ 0.24	$ 0.14
Depreciation, depletion, and amortization	$ 1.28	$ 1.16	$ 1.19	$ 1.13	$ 1.33	$ 1.13	$ 0.99
General and administrative, net of reimbursement	$ 0.28	$ 0.28	$ 0.27	$ 0.21	$ 0.18	$ 0.13	$ 0.10

(1) Represents the total weighted average year-end prices for all our reserves, both domestically and in New Zealand.

(2) 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 proved reserves added during the period.

(3) Calculated for a three-year period ending with the year presented by dividing the increase in net proved reserves by the production quantities for such period.

(4) Natural gas production for the years ended 2000 and 1999 includes 405 MMcf and 728 MMcf, respectively, delivered under a 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.

(5) We combine NGLs with oil for reporting purposes. Prior to 2002, we combined NGLs with natural gas for reporting purposes. Production of NGLs for the three months ended March 31, 2004 and 2003 was 278 Mbls and 173 Mbls at an average price of $22.30 and $21.90 per barrel, respectively. Production of NGLs for 2003 and 2002 was 823 Mbls and 1,174 Mbls, at an average price of $17.60 and $12.82 per barrel, respectively.

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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.

Risks Relating to our Business

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. The recent record high oil and natural gas prices may not continue and could drop precipitously in a short period of time. The prices for oil and natural gas are subject to wide fluctuation in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty, worldwide economic conditions, weather conditions, 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 bank credit facility because of lower oil and natural 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 level of debt could reduce our financial flexibility, and we currently have the ability to incur substantially more debt, including secured debt.

As of March 31, 2004, after giving effect to this offering and the application of the net proceeds thereof, our total debt would have comprised approximately 47% of our total capitalization. Although our bank credit facility and indentures will limit our ability and the ability of our restricted subsidiaries to incur additional indebtedness, we will be permitted to incur significant additional indebtedness, including secured indebtedness, in the future if specified conditions are satisfied. All borrowings under our bank credit facility will be effectively senior to the notes offered hereby to the extent of the value of the collateral securing those borrowings. Our current level of indebtedness:

- will require us to dedicate a substantial portion of our cash flow to the payment of interest;
- will subject us to a higher financial risk in an economic downturn due to substantial debt service costs;
- may 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.

Higher levels of indebtedness would increase these risks.

Estimates of proved reserves are uncertain, and revenues from production may vary significantly from expectations.

The quantities and values of our proved reserves included in this prospectus supplement and in the documents that 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 natural gas reserves, future prices for oil and natural gas, timing and amounts of development expenditures and operating expenses, all of which will vary from those assumed in our estimates. These variances may be significant.

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

At December 31, 2003, approximately 41% 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.

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. When oil and natural gas prices decrease, our cash flow decreases, resulting in less available cash to drill and replace our reserves and an increased need to draw on our bank credit facility.

Drilling wells is speculative and capital intensive.

Developing and exploring properties for oil and natural gas requires significant capital expenditures and involves a high degree of financial risk. 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 or completion of an oil or gas well does not ensure a profit on investment. Exploratory wells bear a much greater risk of loss than development wells. 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.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition, or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas, or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- fires and explosions;

personal injuries and death; and

natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect our financial condition.

We are exposed to the risk of fluctuations in foreign currencies, primarily the New Zealand dollar.

Fluctuations in rates between the New Zealand dollar and U.S. dollar may impact our financial results from our New Zealand subsidiaries since we have receivables, liabilities, and natural gas and NGL sales contracts denominated in New Zealand dollars. We do not hedge against the risks associated with fluctuations in exchange rates. Although we may use hedging techniques in the future, we may not be able to eliminate or reduce the effects of currency fluctuations. As a result, exchange rate fluctuations could have an adverse impact on our operating results.

We have incurred a write-down of the carrying values of our properties in the past and could incur additional write-downs in the future.

Under the full cost method of accounting, SEC accounting rules require that on a quarterly basis we review the carrying value of our oil and gas properties on a country by country basis for possible write-down or impairment. Under these rules, capitalized costs of proved reserves may not exceed a ceiling calculated 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 resulted in a charge to earnings and a reduction of stockholders equity, but did not impact our cash flow from operating activities. If commodity prices decline or if we have downward reserve revisions, we could incur additional write-downs in the future.

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

To finance acquisitions, we may need to substantially alter or increase our capitalization through the use of our bank credit facility, the issuance of debt or equity securities, the sale of production payments, or by other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for any such acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Reserves on acquired properties may not meet our expectations, and we may be unable to identify liabilities associated with acquired properties or obtain protection from sellers against associated liabilities.

Property acquisition decisions are based on various assumptions and subjective judgments that are speculative. Although available geological and geophysical information can provide information about the potential of a property, it is impossible to predict accurately a property s production and profitability. In addition, we may have difficulty integrating future acquisitions into our operations, and they may not achieve our desired profitability objectives. Likewise, as is customary in the industry, we generally acquire oil and gas acreage without any warranty of title except through the transferor. In many instances, title opinions are not obtained if, in our judgment, it would be uneconomical or impractical to do so. Losses may result from title defects or from defects in the assignment of leasehold rights. While our current operations are primarily in Louisiana, Texas, and New Zealand, we may pursue acquisitions of properties located in other geographic areas, which would decrease our geographical concentration, and could also be in areas in which we have no or limited experience.

In addition, our assessment of acquired properties may not reveal all existing or potential problems or liabilities, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform, or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of acquired properties in addition to the risk that the properties may not perform in accordance with our expectations.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

We describe some of our current prospects and our plans to explore those prospects in this prospectus supplement. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities, if at all, to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects, or producing fields will be applicable to our drilling prospects.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit future revenues from price increases and expose us to risk of financial loss.

We enter into hedging transactions for our oil and natural gas production to reduce exposure to fluctuations in the price of oil and natural gas, primarily to protect against declines in prices. Our hedges at year-end 2003 consisted of natural gas price floors with strike prices lower than the period end prices. Our hedging transactions have also consisted of financially settled crude oil and natural gas forward sales contracts with major financial institutions as well as crude oil price floors. We intend to continue to enter into these types of hedging transactions in the foreseeable future. Hedging transactions expose us to risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations, or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions other than floors may limit the benefit we would have otherwise received from increases in the price for oil and natural gas. Additionally, hedging transactions other than floors may expose us to cash margin requirements.

We may have difficulty competing for oil and gas properties or supplies.

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

Governmental laws and regulations are costly and stringent, especially those relating to environmental protection.

Our domestic exploration, production, and marketing operations are subject to complex and stringent federal, state, and local laws and regulations governing the discharge of substances into the environment or otherwise relating to environmental protection. These laws and regulations affect the costs, manner, and feasibility of our operations and require us to make significant expenditures in our efforts to comply. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, the imposition of investigatory and remedial obligations, and the issuance of injunctions that could limit or prohibit our operations. In addition, some of these laws and regulations may impose joint and several, strict liability for contamination resulting from spills, discharges, and releases of substances, including petroleum hydrocarbons and other wastes, without regard to fault or the legality of the original conduct. Under such laws and regulations, we could be required to remove or remediate previously disposed substances and property contamination, including wastes disposed or released by prior owners or operations. Changes in or additions to environmental laws and regulations occur frequently, and any changes or additions that result in more stringent and costly waste handling, storage, transport, disposal, or cleanup requirements could have a material adverse effect our operations and financial position.

Our operations outside of the United States could also be subject to similar foreign governmental controls and restrictions pertaining to protection of human health and the environment. These controls and restrictions may include the need to acquire permits, prohibitions on drilling in certain environmentally sensitive areas, performance of investigatory or remedial actions for any releases of petroleum hydrocarbons or other wastes caused by us or prior owners or operators, closure, and restoration of facility sites, and payment of penalties for violations of applicable laws and regulations.

Risks Relating to the Notes

The notes are not secured by our assets and are effectively subordinated to all of our secured indebtedness to the extent of the value of assets securing such indebtedness.

The notes will be our general unsecured obligations and will be effectively subordinated in right of payment to all of our secured indebtedness to the extent of the value of the assets securing such indebtedness. If we become insolvent or are liquidated, our assets that serve as collateral under our secured indebtedness would be made available to satisfy our obligations under any secured debt before any payments are made on the notes. Our obligations under our bank credit facility are secured by substantially all of our domestic assets and a majority of the capital stock of our New Zealand operating subsidiaries. As of March 31, 2004, after giving effect to this offering and the application of the net proceeds thereof, we would have $17.9 million of indebtedness outstanding under our bank credit facility with the ability to borrow up to $231.3 million of additional indebtedness under the facility. See Description of Existing Indebtedness Bank Credit Facility, and Description of the Notes Certain Covenants Limitation on Indebtedness.

Your right to receive payments on these notes is effectively subordinated to the rights of existing and future creditors of any subsidiaries that are not guarantors on the notes.

Initially none of our subsidiaries are required to guarantee the notes offered by this prospectus supplement. In addition, we may be able to designate one or more subsidiaries in the future as unrestricted subsidiaries, which would not be required to guarantee the notes. As a result, holders of the notes will be effectively subordinated to the indebtedness and other liabilities of these subsidiaries, including trade creditors. Therefore, in the event of the insolvency or liquidation of a foreign or an unrestricted subsidiary, following payment by that subsidiary of its liabilities, such subsidiary may not have sufficient remaining assets to make payments to us as a shareholder or otherwise. In the event of a default by any such subsidiary under any credit arrangement or other indebtedness, its creditors could accelerate such debt, prior to such subsidiary distributing amounts to us that we could have used to make payments on the notes.

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 bank credit facility or other debt agreements.

If a change of control occurs and we are prohibited from repurchasing the notes, our failure to do so would constitute a default under the indenture, which in turn is likely to be a default under our bank credit facility and our outstanding senior subordinated 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.

Our domestic subsidiaries in the future may be required to guarantee our obligations under the notes if they incur indebtedness or issue preferred stock. The guarantees would be senior unsecured obligations of such subsidiaries. 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 will receive net proceeds from this offering of approximately $146.0 million, after deducting estimated expenses and the underwriters discounts. We intend to use approximately $131.4 million of the net proceeds to repurchase our outstanding 10 1/4% senior subordinated notes due 2009, either through a tender offer or redemption or combination thereof. We intend to use the remainder to repay indebtedness under our bank credit facility and for general corporate purposes. Prior to the repurchase of our 10 1/4% senior subordinated notes due 2009, we intend to use a portion of the net proceeds to repay all outstanding indebtedness under our bank credit facility.

At May 31, 2004, the outstanding balance under our bank credit facility was approximately $31.9 million, excluding letters of credit, with an average interest rate of 2.45%, and we had approximately $217.3 million of borrowing capacity available. During the last year, funds were drawn on our bank credit facility to accelerate our drilling program and for general corporate purposes.

CAPITALIZATION

The following table sets forth our consolidated cash and cash equivalents and capitalization as of March 31, 2004 on a historical basis and as adjusted to give effect to this offering and the application of the estimated net proceeds as described above under Use of Proceeds. You should read this table in conjunction with Use of Proceeds, Management s Discussion and Analysis of Financial Condition and Results of Operations, Description of Existing Indebtedness, and the consolidated financial statements and the notes thereto appearing elsewhere in this prospectus supplement.

	As of March 31, 2004	
	Historical	**As Adjusted(1)**
	(In thousands)	
Cash and cash equivalents	$ 4,399	$ 4,399
Debt:		
Bank borrowings	32,500	17,906
10 1/4% senior subordinated notes due 2009	124,377	
9 3/8% senior subordinated notes due 2012	200,000	200,000
% senior notes offered hereby		150,000
Total debt	$356,877	$367,906
Total stockholders equity	413,827	407,861
Total capitalization	$770,704	$775,768

(1) Assumes redemption of the outstanding principal amount of our 10 1/4% senior subordinated notes due 2009, plus a redemption premium of $6.4 million.

SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The selected historical consolidated financial data presented below as of and for each of the five years ended December 31, 2003 has been derived from our audited consolidated financial statements. The selected historical consolidated financial data as of and for each of the three months ended March 31, 2004 and 2003 has been derived from our unaudited consolidated financial statements. For a discussion of our significant financial results and conditions during 2003, 2002, and 2001 and the three month periods ended March 31, 2004 and 2003, see Management s Discussion and Analysis of Financial Condition and Results of Operations in this prospectus supplement.

	Three Months Ended March 31,		Year Ended December 31,				
	2004	2003	2003	2002	2001	2000	1999
	(In thousands, except ratios)						
Income Statement Data:							
Revenues:							
Oil and gas sales	$ 65,954	$ 54,850	$211,033	$141,196	$181,185	$189,139	$108,899
Gain on asset disposition				7,333			
Price risk management and other, net	(598)	(1,350)	(2,132)	1,441	2,622	2,486	1,772
Total revenues	65,356	53,500	208,901	149,970	183,807	191,625	110,671
Costs and expenses:							
General and administrative, net of reimbursement	4,030	3,557	14,097	10,565	8,187	5,586	4,497
Depreciation, depletion, and amortization	18,296	14,912	63,072	56,224	59,502	47,771	42,349
Accretion of asset retirement obligation	170	215	857				
Lease operating costs	9,626	7,313	33,833	29,656	24,990	19,227	13,736
Severance and other taxes	6,247	4,594	19,034	11,841	11,730	9,993	5,910
Interest expense, net	6,901	6,685	27,269	23,275	12,627	15,968	14,443
Other expenses					2,102	984	
Write-down of oil and gas properties(1)					98,862		
Total costs and expenses	45,270	37,276	158,162	131,562	218,000	99,530	80,935
Income (loss) before income taxes and change in accounting principle	20,086	16,224	50,739	18,408	(34,193)	92,095	29,736
Provision (benefit) for income taxes	5,498	5,739	16,469	6,485	(12,238)	32,911	10,450
Income (loss) before change in accounting principle	14,588	10,485	34,271	11,923	(21,955)	59,184	19,286
Cumulative effect of change in accounting principle (net of taxes)(2)		4,377	4,377		393		
Net income (loss)	$ 14,588	$ 6,108	$ 29,894	$ 11,923	$ (22,348)	$ 59,184	$ 19,286
Other Financial Data:							
EBITDA(3)	$ 45,454	$ 38,036	$141,937	$ 90,575	$136,799	$155,835	$ 86,528
Net cash provided by operating activities	39,596	26,799	110,827	71,626	139,884	128,197	73,603

Capital expenditures	45,150	26,335	144,503	155,234	275,126	173,277	78,113
Ratio of earnings to fixed charges(4)	3.2x	2.7x	2.3x	1.4x		5.2x	2.4x
Ratio of EBITDA to cash interest(3)(5)	6.6x	5.7x	4.3x	3.5x	7.4x	7.5x	6.6x
Balance Sheet Data (at end of period):							
Working capital (deficit)	$ (15,370)	$ (5,247)	$ (35,099)	$ (17,116)	$ (36,492)	$ (22,452)	$ 16,535
Total assets	886,369	786,549	859,839	767,006	671,683	572,387	454,299
Long term debt:							
Bank borrowings	32,500	5,700	15,900		134,000	10,600	
6 1/4% convertible subordinated notes							115,000
10 1/4% senior subordinated notes	124,377	124,292	124,355	124,272	124,197	124,129	124,068
9 3/8% senior subordinated notes	200,000	200,000	200,000	200,000			
Stockholders equity	413,827	371,856	397,391	365,073	312,653	332,154	170,404

(1) Due primarily to a decline in prices for both oil and gas in the fourth quarter of 2001 a pre-tax domestic full cost ceiling write-down of oil and gas properties of $98.9 million, or $63.5 million after-tax, was necessary at December 31, 2001.

(2) We adopted SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, effective January 1, 2001 resulting in a one-time net of taxes charge of $0.4 million in the first quarter of 2001, which is recorded as a cumulative effect of change in accounting principle. We adopted SFAS No. 143, Accounting for Asset Retirement Obligations, effective January 1, 2003. Our adoption of SFAS No. 143 resulted in a one-time net of taxes charge of $4.4 million in the first quarter of 2003, which is recorded as a cumulative effect of change in accounting principle.

(3) EBITDA represents income before interest expense, income tax, depreciation, depletion, and amortization, write-down of oil and gas properties, accretion of asset retirement obligation, and gain on asset disposition. 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. 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.

EBITDA is not intended to represent net income as defined by GAAP and such information should not be considered as an alternative to net income, cash flow from operations or any other measure of performance prescribed by GAAP in the United States. The following table reconciles net income to EBITDA for the periods presented:

	Three Months Ended March 31,		**Year Ended December 31,**				
	2004	**2003**	**2003**	**2002**	**2001**	**2000**	**1999**
				(In thousands)			
Net income (loss)	$14,588	$ 6,108	$ 29,894	$11,923	$ (22,348)	$ 59,184	$19,286
Provision (benefit) for income taxes	5,498	5,739	16,469	6,485	(12,238)	32,911	10,450
Cumulative effect of change in accounting principle (net of taxes)		4,377	4,377		393		
Interest expense, net	6,901	6,685	27,269	23,275	12,627	15,968	14,443
Depreciation, depletion, and amortization, and accretion of asset retirement obligation	18,466	15,127	63,929	56,224	59,502	47,771	42,349
Gain on asset disposition				(7,333)			
Write-down of oil and gas properties					98,862		
EBITDA	$45,454	$38,036	$141,937	$90,575	$136,799	$155,835	$86,528

(4) 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 charge incurred in 2001 resulting from a write-down in the carrying value of natural gas and oil properties, 2001 earnings were insufficient by $40.2 million to cover fixed charges in 2001. If this non-cash charge was excluded, the ratio of earnings to fixed charges would have been 4.1x for 2001.

(5) Cash interest is the total amount of interest paid on our obligations, including capitalized amounts.

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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 4.

Overview

For the first three months of 2004, we had revenues of $65.4 million and production of 14.3 Bcfe. Our revenues were bolstered by strong oil and natural gas prices and a 35% increase in domestic production over production in the same period in 2003. We continued to focus our efforts and capital throughout the quarter on better infrastructure, increased production and the development of longer life oil reserves in the Lake Washington area. In the first quarter of 2004, we produced over 11,300 gross (9,300 net) BOE per day in Lake Washington, compared to approximately 4,500 gross (3,700 net) BOE per day in the same period of 2003. New Zealand accounted for 3.9 Bcfe of production in the first quarter of 2004, a 25% decrease from production in the same period in 2003. Natural gas production in New Zealand declined due to minimum takes from the gas purchaser at TAWN. Increased use of hydroelectricity in New Zealand has contributed to a short-term reduction in market demand, which is expected to continue at least through the second quarter of this year. While our fields at TAWN have been able to meet minimum contracted volumes to date, it is anticipated, due to accelerated production in 2002 and 2003 along with natural production declines, that these fields will not be able to meet the minimum contracted volumes beginning in the second half of this year without additional development. These minimum contracted volumes represent the volumes of gas that the purchasers under the contracts must take if the fields produce such volumes. There is no penalty if the fields are unable to produce these minimum contracted volumes. We are currently considering drilling a development well in the Tariki field in the second half of this year, but to some extent, our ongoing activity at TAWN is affected by discussions with the gas purchaser. New Zealand natural gas and NGL contracts are denominated in the New Zealand dollar, which has significantly strengthened during the last several years against the U.S. dollar. This has resulted in increased prices for natural gas and NGLs. We continue to see a tightening natural gas market and strengthening natural gas prices in New Zealand. For 2004, we believe we are positioned for production growth of 11% to 17% and proved reserve growth of 5% to 8%, and expect commodity prices to remain strong.

Our production costs increased in the first quarter of 2004, predominately due to increased production in Lake Washington, increased severance taxes, currency exchange rates, and maintenance activities in New Zealand. Our general and administrative expenses increased in the first quarter of 2004, predominantly due to an increase in franchise tax expense, increased costs related to our corporate governance activities and compliance with the Sarbanes-Oxley Act, as well as higher costs in our New Zealand operations due to currency exchange rates. We are working to reduce our production and general and administrative costs on a per unit of production basis for the remainder of 2004.

Our debt to PV-10 ratio has remained relatively steady at 22% at December 31, 2003 and 21% at March 31, 2004. Our debt to capitalization ratio was 46% at December 31, 2003 and March 31, 2004. We believe that our current cash flow is best utilized on capital projects rather than for other corporate purposes, such as reducing our debt. We will continue to look for opportunities in 2004 to improve our balance sheet and liquidity, but expect our capital expenditures to continue to equal or modestly exceed our cash flow for the near term.

Results of Operations Three Months Ended March 31, 2004 and 2003

Revenues. Our revenues in the first quarter of 2004 increased by 22% compared to revenues in the same period of 2003, due primarily to increases in oil prices and in production from our Lake Washington area. Revenues from our oil and gas sales comprised substantially all of our net revenues for the first quarter of 2004 and 2003. Natural gas production comprised 41% of our production volumes in the first quarter of 2004 and 60% in the same period in 2003. Domestic natural gas production comprised 52% of our total natural gas production volumes in the first quarter of 2004 and 47% in the comparable period of 2003.

The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the three months ended March 31, 2004 and 2003:

	Three Months Ended March 31,			
	Oil and Gas Sales		Oil and Gas Sales Volumes	
Area	2004	2003	2004	2003
	(In millions)		(Bcfe)	
AWP Olmos	$11.7	$12.5	2.6	2.0
Brookeland	4.6	4.3	1.0	0.8
Lake Washington	28.9	11.1	5.1	2.0
Masters Creek	5.1	9.4	1.0	1.7
Other	4.4	6.5	0.7	1.2
Total Domestic	$54.7	$43.8	10.4	7.7
Rimu/ Kauri	4.3	1.5	1.1	0.5
TAWN	7.0	9.6	2.8	4.7
Total New Zealand	$11.3	$11.1	3.9	5.2
Total	$66.0	$54.9	14.3	12.9

We combine NGLs with oil for reporting purposes. Prior to 2002, we combined NGLs with natural gas for reporting purposes. The following table provides additional information regarding our oil, NGL, and natural gas sales:

	Sales Volume				Average Sales Price		
	Oil (MBbl)	NGL (MBbl)	Gas (Bcf)	Combined (Bcfe)	Oil (Bbl)	NGL (Bbl)	Gas (Mcf)
Three Months Ended March 31, 2004:							
Domestic	1,018	211	3.1	10.4	$33.95	$24.31	$4.90
New Zealand	106	67	2.8	3.9	$36.03	$16.00	$2.27
Total	1,124	278	5.9	14.3	$34.14	$22.30	$3.64
Three Months Ended March 31, 2003:							
Domestic	578	100	3.6	7.7	$32.80	$28.47	$6.03
New Zealand	112	73	4.1	5.2	$32.36	$12.89	$1.62
Total	690	173	7.7	12.9	$32.73	$21.90	$3.71

Oil and gas sales in the first quarter of 2004 increased by 20%, or $11.1 million, from the level of oil and gas sales for the same period in 2003. The increase in production volumes during the first quarter of 2004 was primarily due to increased production from our Lake Washington, AWP, and Brookeland areas domestically and the Rimu/ Kauri area in New Zealand.

In the first quarter of 2004, our $11.1 million increase in oil, NGL, and natural gas sales resulted from:

Volume variances that had a $9.8 million favorable impact on sales, comprised of a $16.5 million increase attributable to a 539,000 Bbl increase in oil and NGL sales volumes, offset by a $6.7 million decrease associated with a 1.8 Bcf decrease in gas sales volumes; and

Price variances that had a $1.3 million favorable impact on sales, of which $1.7 million was attributable to a 4% increase in average combined oil and NGL prices, partially offset by a $0.4 million decrease attributable to a 2% decrease in average natural gas prices.

Costs and Expenses. Our total expenses in the first quarter of 2004 increased $8.0 million, or 21%, compared to expenses in the same period in 2003. The majority of the increase was due to a $3.4 million increase in depreciation, depletion, and amortization and a $2.3 million increase in lease operating costs, both of which increased as our production volumes increased in the 2004 period.

Our first quarter of 2004 general and administrative expenses, net, increased $0.5 million, or 13%, from the level of such expenses in the same 2003 period. This increase was due primarily to an increase in franchise tax expense, increased costs related to our corporate governance activities and compliance with the Sarbanes-Oxley Act, as well as higher costs in our New Zealand operations due to the increase in the currency exchange rates between the New Zealand dollar and the U.S. dollar. Our general and administrative expenses per Mcfe produced were $0.28 per Mcfe in both the first quarter of 2004 and 2003. The portion of supervision fees recorded as a reduction of general and administrative expenses was $1.3 million for the first quarter of 2004 and $0.7 million for the same period in 2003.

Depreciation, depletion, and amortization of our oil and gas properties, or DD&A, increased $3.4 million, or 23%, in the first quarter of 2004 from 2003 levels. Domestically, DD&A increased $4.7 million in the 2004 period, mainly due to higher production. In New Zealand, DD&A decreased by $1.3 million in the 2004 period due to decreased production. Our DD&A rate per Mcfe of production was $1.28 in the first quarter of 2004 and $1.16 in the comparable 2003 period.

We recorded $0.2 million of accretion on our asset retirement obligation in both the first quarters of 2004 and 2003.

Our lease operating costs in the first quarter of 2004 increased $2.3 million, or 32%, over the level of such expenses in the comparable 2003 period. Approximately $1.4 million of the increase in lease operating costs during the first quarter of 2004 was related to our domestic operations, which increased due to higher production from our Lake Washington, AWP, and Brookeland areas in that period. In New Zealand, production costs increased by $0.9 million in the first quarter of 2004 mainly due to the increase in currency exchange rates between the New Zealand dollar and the U.S. dollar, and scheduled maintenance activities in the first quarter of 2004. The portion of supervision fees recorded as a reduction to production costs was $0 for the 2004 period and $0.5 million for the 2003 period. Our lease operating costs per Mcfe produced were $0.67 in the first quarter of 2004 and $0.57 in the same period of 2003.

Severance and other taxes in the first quarter of 2004 increased $1.7 million, or 36%, over the level of such expenses in the comparable 2003 period. The increase was due primarily to higher commodity prices and increased Lake Washington production. Severance and other taxes, as a percentage of oil and gas sales, were approximately 9% and 8% in the first quarters of 2004 and 2003, respectively.

Interest expense on our 9 3/8% senior subordinated notes issued in April 2002, including amortization of debt issuance costs, totaled $4.8 million in both the first quarters of 2004 and 2003, respectively. Interest expense on our 10 1/4% senior subordinated notes issued in August 1999, including amortization of debt issuance costs, totaled $3.3 million in both the first quarters of 2004 and 2003. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled $0.4 million in both the first quarters of 2004 and 2003. The total interest cost in the first quarter of 2004 was $8.5 million, of which $1.6 million was capitalized. The total interest cost in the first quarter of 2003 was $8.5 million, of which $1.8 million was capitalized.

Income tax expense in the first quarter of 2004 includes a reduction from the U.S. statutory rate, primarily from the result of the currency exchange rate effect on the New Zealand deferred tax, along with a reduction in tax expense primarily attributable to an adjustment of the tax basis of the TAWN properties acquired in 2002.

As discussed in Note 1 to the Consolidated Financial Statements, we adopted SFAS No. 143, Accounting for Asset Retirement Obligations, on January 1, 2003. Our adoption of SFAS No. 143 resulted in a one-time net of taxes charge of $4.4 million, which is recorded as a Cumulative Effect of Change in Accounting Principle in the 2003 consolidated statement of income.

Net Income. Our net income in the first quarter of 2004 of $14.6 million was 139% higher than our first quarter of 2003 net income of $6.1 million due to higher commodity prices, increased domestic production, and the effect of the cumulative effect of change in accounting principle recognized in the first quarter of 2003.

Results of Operations Years Ended 2003, 2002, and 2001

Revenues. Our revenues in 2003 increased by 39% compared to revenues in 2002, due primarily to increases in oil and natural gas prices and production from our Lake Washington and New Zealand areas. Revenues in 2002 decreased by 18% compared to 2001 revenues primarily due to a drop in domestic natural gas prices in 2002. Revenues from our oil and gas sales comprised substantially all of net revenues for 2003, 94% of total revenues for 2002, and 99% of total revenues for 2001. Natural gas production comprised 53% of our production volumes in 2003, 55% in 2002, and 59% in 2001. Domestic natural gas production comprised 49% of our total natural gas production volumes in 2003, 58% in 2002, and 100% in 2001.

The following table provides information regarding the changes in the sources of our oil and gas sales and volumes for the years ended December 31, 2003, 2002, and 2001.

	Oil and Gas Sales			Oil and Gas Sales Volume		
Area	2003	2002	2001	2003	2002	2001
		(In millions)			(Bcfe)	
AWP Olmos	$ 43.7	$ 33.1	$ 56.1	8.4	10.9	13.0
Brookeland	16.4	11.9	25.1	3.9	4.1	6.5
Lake Washington	59.5	18.5	4.6	12.1	4.4	1.2
Masters Creek	25.7	32.3	62.3	5.7	9.7	15.3
Other	18.9	16.3	31.3	3.7	5.2	8.3
Total Domestic	$164.2	$112.1	$179.4	33.8	34.3	44.3
Rimu/ Kauri	11.6	4.0	1.8	3.3	1.5	0.5
TAWN	35.2	25.1		16.1	14.0	
Total New Zealand	$ 46.8	$ 29.1	$ 1.8	19.4	15.5	0.5
Total	$211.0	$141.2	$181.2	53.2	49.8	44.8

We combine NGLs with oil for reporting purposes. Prior to 2002, we combined NGLs with natural gas for reporting purposes.

Oil and gas sales in 2003 increased by 49%, or $69.8 million, from the level of those revenues for 2002, and our net sales volumes in 2003 increased by 7%, or 3.4 Bcfe, over net sales volumes in 2002. Average prices for oil increased to $29.89 per Bbl in 2003 from $24.52 per Bbl in 2002. Average natural gas prices increased to $3.42 per Mcf in 2003 from $2.30 per Mcf in 2002. Average NGL prices increased to $17.60 per Bbl in 2003 from $12.82 per Bbl in 2002.

In 2003, our $69.8 million increase in oil, NGL, and natural gas sales resulted from:

Price variances that had a $59.0 million favorable impact on sales, of which $31.4 million was attributable to the 49% increase in average natural gas prices and $27.6 million was attributable to the 32% increase in average combined oil and NGL prices; and

Volume variances that had a $10.8 million favorable impact on sales, with $8.8 million of increases attributable to the 422,000 Bbl increase in oil and NGL sales volumes, and $2.0 million of the increases from the 0.9 Bcf increase in natural gas sales volumes.

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

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

Price variances that had a $59.0 million unfavorable impact on sales, of which $6.6 million was attributable to the 8% decrease in average combined oil and NGL prices and $52.4 million was attributable to the 46% decrease in average natural gas prices; and

Volume variances that had a $19.0 million favorable impact on sales, with $16.2 million of increases attributable to the 715,000 Bbl increase in oil and NGL sales volumes, and $2.8 million of the increases from the 0.7 Bcf increase in natural gas sales volumes.

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

	Sales Volume			Average Sales Price	
	Oil	**Gas**	**Combined**	**Oil**	**Natural Gas**
	(MBbl)	**(Bcf)**	**(Bcfe)**	**(Bbl)**	**(Mcf)**
2001:					
First	603	6.7	10.3	$27.63	$6.86
Second	691	7.1	11.3	$26.05	$4.66
Third	813	6.8	11.7	$23.76	$2.94
Fourth	948	5.9	11.5	$16.02	$2.21
Total	3,055	26.5	44.8	$22.64	$4.23
2002:					
First	944	6.6	12.3	$16.10	$1.72
Second	1,002	6.7	12.7	$20.98	$2.60
Third	908	6.7	12.2	$23.05	$2.32
Fourth	916	7.1	12.6	$23.55	$2.55
Total	3,770	27.1	49.8	$20.88	$2.30
2003:					
First	864	7.6	12.9	$30.55	$3.71
Second	1,033	7.1	13.3	$25.48	$3.47
Third	1,164	6.7	13.6	$26.60	$3.17
Fourth	1,132	6.6	13.4	$27.84	$3.29
Total	4,193	28.0	53.2	$27.47	$3.42

We combine NGLs with oil for reporting purposes. Prior to 2002, we combined NGLs with natural gas for reporting purposes. For 2003 and 2002, NGL production was 823 MBbls and 1,174 MBbls, respectively, at an average price of $17.60 and $12.82 per barrel, respectively.

Costs and Expenses. Our expenses in 2003 increased $26.6 million, or 20%, compared to 2002 expenses. The majority of the increase was due to a $11.4 million increase in oil and gas production costs and a $6.8 million increase in DD&A, both of which increased as our production volumes increased in 2003. Our expenses in 2002 decreased by $86.4 million, or 40%, compared to 2001 expenses. This decrease was due primarily to a $98.9 million non-cash write-down of domestic oil and gas properties in 2001.

Our 2003 general and administrative expenses, net, increased $3.5 million, or 33%, from the level of such expenses in 2002, while 2002 general and administrative expenses increased $2.4 million, or 29%, over 2001 levels. These increases in 2002 and 2003 were due primarily to our increased activities in New Zealand and a reduction in reimbursements from partnerships that we managed as almost all of these partnerships have been liquidated. In addition, our 2003 expenses increased due to an increase in franchise tax expense and increased costs related to our corporate governance activities and compliance with the Sarbanes-Oxley Act. Our general and administrative expenses per Mcfe produced increased to $0.27 per Mcfe in 2003 from $0.21 per Mcfe in 2002 and $0.18 per Mcfe in 2001. The portion of supervision fees recorded as a reduction to general and administrative expenses was $3.6 million for 2003, $3.1 million for 2002, and $3.5 million for 2001.

DD&A increased $6.8 million, or 12%, in 2003 from 2002 levels, while 2002 DD&A decreased $3.3 million, or 6%, from 2001 levels. Domestically, DD&A increased $1.0 million in 2003 due to increases in the depletable oil and gas property base, offset by slightly lower production in the 2003 period and higher reserve volumes that were added primarily through our Lake Washington activities. In New Zealand, DD&A increased by $5.8 million in 2003 due to increased production in the 2003 period. In 2002, our domestic DD&A decreased by $15.6 million due to lower production in the 2002 period and the domestic non-cash write-down of oil and gas properties in the fourth quarter of 2001 that decreased our depletable base, along with higher reserve volumes that were added primarily through our Lake Washington activities. In New Zealand, our 2002 DD&A increased $12.3 million as our production and depletable oil and gas property base both increased in the 2002 period due primarily to the TAWN acquisition. Our DD&A rate per Mcfe of production was $1.19 in 2003, $1.13 in 2002, and $1.33 in 2001, reflecting variations in per unit cost of reserves additions.

We recorded $0.9 million of accretion on our asset retirement obligation in 2003 associated with the adoption of SFAS No. 143 implemented on January 1, 2003.

Our production costs in 2003 increased $11.4 million, or 27%, over such expenses in 2002, while those expenses in 2002 increased $4.8 million, or 13%, over such expenses in 2001. Approximately $6.2 million of the increase in production costs during 2003 was related to domestic severance taxes, which increased along with commodity prices and higher production from our Lake Washington area in that period. In New Zealand, production costs increased by $5.2 million in 2003 mainly due to royalty payments made on higher production in the period. In 2002, production costs increased as our New Zealand activities increased, partially offsetting the domestic production costs decrease, which mainly was due to a decrease in production volumes. The portion of supervision fees recorded as a reduction to production costs was $1.5 million for 2003, $2.1 million for 2002, and $3.3 million for 2001. Our production costs per Mcfe produced were $0.99 in 2003, $0.83 in 2002, and $0.82 in 2001.

Interest expense on our 9 3/8% senior subordinated notes issued in April 2002, including amortization of debt issuance costs, totaled $19.1 million in 2003 and $13.5 million in 2002. Interest expense on our 10 1/4% senior subordinated notes issued in August 1999, including amortization of debt issuance costs, totaled $13.2 million in both 2003 and 2002 and $13.1 million in 2001. Interest expense on our bank credit facility, including commitment fees and amortization of debt issuance costs, totaled $1.6 million in 2003, $3.6 million in 2002, and $5.8 million in 2001. Other interest cost was $0.3 million in 2003. Our total interest cost in 2003 was $34.2 million, of which $6.9 million was capitalized. Our total interest cost in 2002 was $30.3 million, of which $7.0 million was capitalized. Our 2001 total interest cost was

$18.9 million, of which $6.3 million was capitalized. We capitalize a portion of interest related to unproved properties. The increase in interest expense in 2003 and 2002 was attributed to the replacement of our bank borrowings in April 2002 with our 9 3/8% senior subordinated notes that carry a higher interest rate.

In the fourth quarter of 2001, we recognized a domestic non-cash write-down of oil and gas properties, as discussed in Note 1 to the Consolidated Financial Statements. Lower prices for both oil and natural gas at December 31, 2001, necessitated a pre-tax domestic full-cost ceiling write-down of $98.9 million, or $63.5 million after tax. In addition to this domestic ceiling write-down, we also expensed $2.1 million of charges in the fourth quarter of 2001 for certain delinquent accounts receivable, the majority of which were related to natural 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.

Income tax expense in 2003 includes a reduction of approximately $1.3 million from the U.S. statutory rate, primarily from the result of the currency exchange rate effect on the New Zealand deferred tax. This amount was partially offset by higher deferred state taxes and other items.

As discussed in Note 1 to the Consolidated Financial Statements, we adopted SFAS No. 143 on January 1, 2003. Our adoption of SFAS No. 143 resulted in a one-time net of taxes charge of $4.4 million, which was recorded as a cumulative effect of change in accounting principle in the 2003 consolidated statement of income. We adopted SFAS No. 133, as amended, on January 1, 2001. Our adoption of SFAS No. 133 resulted in a one-time net of taxes charge of $0.4 million, which was recorded as a cumulative effect of change in accounting principle in the 2001 consolidated statement of income.

Net Income (Loss). Our net income in 2003 of $29.9 million was 151% higher than our 2002 net income of $11.9 million due to higher commodity prices and increased production.

Our net income in 2002 of $11.9 million was 153% higher than our 2001 net loss of $(22.3) million due to overall lower costs, as a non-cash write-down of oil and gas properties occurred in 2001 and not in 2002, offset somewhat by lower revenue in 2002 due to lower commodity prices.

Contractual Commitments and Obligations

Our contractual commitments for the next five years and thereafter as of December 31, 2003 are as follows:

	2004	2005	2006	2007	2008	Thereafter	Total
				(In thousands)			
Non-cancelable operating leases	$2,143	$ 493	$159	$157	$125	$ 14	$ 3,090
Capital commitments due to pipeline operators	96						96
Asset retirement obligation(1)	1,704	2,604		129	74	5,626	10,138
Drilling rigs and seismic	5,919						5,919
Senior subordinated notes due 2009(2)						125,000	125,000
Senior subordinated notes due 2012(2)						200,000	200,000
Credit facility(3)		15,900					15,900
Total	$9,862	$18,996	$159	$286	$199	$330,640	$360,143

(1) Amounts shown by year are the fair values at December 31, 2003.
(2) Amounts do not include the interest obligation, which is paid semiannually.
(3) Amounts exclude a $0.8 million standby letter of credit outstanding under this facility.

Commodity Price Trends and Uncertainties

Oil and natural gas prices historically have been volatile and are expected to continue to be volatile in the future. The price of oil increased significantly in the first quarter of 2004 and is currently significantly higher when compared to longer-term historical prices. Factors such as actions taken by OPEC, worldwide

supply disruptions, worldwide economic conditions, weather conditions, and fluctuating currency exchange rates can cause wide fluctuations in the price of oil. Domestic natural gas prices continue to remain high when compared to longer-term historical prices. North American weather conditions, the industrial and consumer demand for natural gas, storage levels of natural gas, and the availability and accessibility of natural gas deposits in North America can cause significant fluctuations in the price of natural gas. Such factors are beyond our control.

Liquidity and Capital Resources

During the first quarter of 2004, we largely relied upon our net cash provided by operating activities of $39.6 million and proceeds from bank borrowings of $16.6 million to fund capital expenditures of $45.1 million and for working capital. During the first quarter of 2003, we relied upon our net cash provided by operating activities of $26.8 million to fund capital expenditures of $26.3 million.

Net Cash Provided by Operating Activities. For the first quarter of 2004, our net cash provided by operating activities was $39.6 million, representing a 48% increase as compared to $26.8 million generated during the first quarter of 2003. The $12.8 million increase was primarily due to an increase of $11.1 million in oil and gas sales for the 2004 period, attributable to higher commodity prices and production, offset in part by higher lease operating costs due to higher domestic production and severance taxes as a result of higher commodity prices in the first quarter of 2004.

Accounts Receivable. Included in our accounts receivable balance, which totaled $29.1 million and $27.4 million at March 31, 2004 and December 31, 2003, respectively, is approximately $2.3 million of receivables related to hydrocarbon volumes produced from 2001 and 2002 that have been disputed since early 2003. We assess the collectibility of trade and other receivables and we accrue a reserve when we believe a receivable may not be collected. At March 31, 2004 and December 31, 2003, we had an allowance for doubtful accounts of $0.8 million. These allowances for doubtful accounts have been deducted from our accounts receivable balances.

Existing Credit Facility. We had $32.5 million in outstanding borrowings under our bank credit facility at March 31, 2004, and $15.9 million in outstanding borrowings at December 31, 2003. Our bank credit facility at March 31, 2004 consisted of a $300.0 million revolving line of credit with a $250.0 million borrowing base. The borrowing base is re-determined at least every six months and was reaffirmed by our bank group at $250.0 million, effective May 1, 2004. At our request, the commitment amount was reduced to $150.0 million effective May 9, 2003. Under the terms of our bank credit facility, we can increase this commitment amount back to the total amount of the borrowing base at our discretion, subject to the terms of the credit agreement. Our revolving credit facility includes, among other restrictions, requirements to maintain certain minimum financial ratios (principally pertaining to working capital, debt, and equity ratios), and limitations on incurring other debt. We are in compliance in all material respects with the provisions of this agreement.

We have signed a commitment letter and fee letter with the administrative agent of our bank group relating to the renewal and extension of our bank credit facility. We anticipate that the renewal and extension will be finalized in June 2004 on substantially the same terms as our existing facility except with a $400.0 million revolving line of credit and a maturity date of October 1, 2008.

Working Capital. Our working capital improved from a deficit of $35.1 million at December 31, 2003, to a deficit of $15.4 million at March 31, 2004. The improvement was primarily due to a decrease in accounts payable and accrued capital costs due to a reduction in our drilling activities at March 31, 2004.

Capital Expenditures. Domestic activities account for the majority of our 2004 capital expenditure budget with the largest allocation going to our Lake Washington area. In Lake Washington, the 2004 budget assumes drilling activity of 25 to 30 development wells and two to four exploratory wells, while we complete an extensive three-dimensional seismic survey and begin analysis of the resulting data to enhance our future drilling program in the area. We plan to drill 15 to 18 development wells in AWP Olmos with the objective of maintaining production levels in that area. Additionally, we expect to conduct ongoing exploratory efforts in our South Texas Garcia Ranch properties. In New Zealand, we plan to drill eight to 12 wells, primarily in the areas in which we had success in 2003. During the first three months of 2004, we used $45.1 million to fund capital expenditures for property, plant, and equipment. These capital expenditures were comprised of:

Domestic expenditures of $36.5 million as follows:

$31.2 million for drilling and developmental activity costs;

$4.7 million of domestic prospect costs, principally prospect leasehold, seismic, and geological costs of unproved prospects;

$0.4 million relating to costs directly associated with evaluating potential producing property acquisitions; and

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

New Zealand expenditures of $8.6 million as follows:

$7.0 million for drilling costs and developmental activity costs;

$1.5 million on prospect costs, principally seismic and geological costs; and

$0.1 million for fixed assets.

We have spent considerable time and capital in 2003 and the first quarter of 2004, on significant facility capacity upgrades in the Lake Washington field to increase facility capacity to more than 20,000 barrels per day for crude oil, up from 9,000 barrels per day capacity in the first quarter of 2003. Facility upgrades, most of which were completed in the fourth quarter of 2003, and the commissioning of these upgrades, led to numerous planned production shut-in periods during the third and fourth quarters of 2003. We have upgraded three production platforms, added new compression for the gas lift system, and installed a new oil delivery system and permanent barge loading facility.

We drilled or participated in drilling 12 domestic development wells and two domestic exploratory wells in the first quarter of 2004. Seven of the development wells and one exploratory well were in the Lake Washington area. Four of the development wells were in the AWP area. One domestic exploratory well and 11 of the domestic development wells were completed. In New Zealand, the Kauri-E3 well was completed while the Kauri-E4 began completion procedures.

For the remaining nine months of 2004, we expect to make capital expenditures of approximately $90.0 to $120.0 million. We currently estimate total capital expenditures for 2004 to be approximately $133.0 to $163.0 million, excluding acquisition costs. Approximately $3.0 to $13.0 million of this will be funded through non-core property dispositions. Capital expenditures for 2003 were $144.5 million. The budget for 2004, is dependent upon operational performance and commodity pricing levels during the year.

We believe that the anticipated internally generated cash flows for 2004, together with borrowings under our bank credit facility, will be sufficient to finance the costs associated with our currently budgeted 2004 capital expenditures. If producing property acquisitions become attractive during 2004, we may access debt and/or equity markets to fund such activity.

During the last nine months of 2004, we anticipate drilling or participating in the drilling of up to an additional 18 to 23 development wells and one to three exploratory wells in our Lake Washington area, an additional eleven to fourteen development wells in our AWP area, and up to five additional wells, with varying working interest percentages, mainly in our South Texas areas. In addition, we plan on drilling an additional two or three Kauri wells, a Tariki well, and four to six Manutahi wells.

Our 2004 capital expenditures continue to be focused on developing and producing long-lived oil and natural gas reserves in our Lake Washington, AWP Olmos, and Rimu/ Kauri areas. This focus should help lessen our overall production decline curve, which would extend our average reserve life. We expect our 2004 total production to increase by 11% to 17% over 2003 levels, primarily from the Lake Washington area. We expect production in our AWP Olmos area to remain relatively flat and production in our other domestic core areas to decrease as limited new drilling is currently budgeted to offset the natural production decline of these properties.

New Accounting Principles

In March 2004, the FASB issued an exposure draft that would amend SFAS No. 123, Accounting for Stock Based Compensation, and SFAS No. 95, Statement of Cash Flows. This exposure draft was issued to improve existing accounting rules and provide more complete, higher quality information for investors on employee stock compensation matters. The comment period for the exposure draft ends June 30, 2004. The exposure draft covers a wide range of equity-based arrangements including stock options. Under the FASB s proposal, share-based payments to employees, including stock options, would be treated the same as other forms of compensation by recognizing the related co