**TABLE OF CONTENTS**

## SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

## FORM 10-K

**(Mark one)**

| | |
|---|---|
| (x) | ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934<br>For the fiscal year ended December 31, 2000 |
| ( ) | TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (NO FEE REQUIRED)<br>For the transaction period from _______ to _______ |

**Commission File Number 0-9592**

# RANGE RESOURCES CORPORATION
**(Exact name of registrant as specified in its charter)**

| | |
|---|---|
| **Delaware**<br>**(State of incorporation)** | **34-1312571**<br>**(I.R.S. Employer Identification No.)** |
| **777 Main Street, Suite 800, Fort Worth, Texas**<br>**(Address of principal executive offices)** | **76102**<br>**(Zip Code)** |

**Registrant's telephone number, including area code:**
**(817) 870-2601**

**Securities registered pursuant to Section 12(b) of the Act:**
**None**

**Common Stock, $.01 par value**
**(Title of class)**

**Securities registered pursuant to Section 12(g) of the Act:**
**None**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ( )

The aggregate market value of voting stock of the registrant held by non-affiliates (excluding voting shares held by officers and directors) was $281,790,768 on March 1, 2001.

Indicate the number of shares outstanding of each of the registrant's classes of stock on March 1, 2001: Common Stock $.01 par value: 50,489,906; Preferred Stock $1 par value: 8,235.

**DOCUMENTS INCORPORATED BY REFERENCE:**
Part III of this report incorporates by reference the Proxy Statement relating to the Registrant's 2001 Annual Meeting of Stockholders.

## RANGE RESOURCES CORPORATION

**Annual Report on Form 10-K**
**Year Ended December 31, 2000**

## PART I

### ITEM 1. BUSINESS

#### General

Range Resources Corporation (“Range”) is engaged in the acquisition and development of oil and gas properties, primarily in the Southwest, Gulf Coast and Appalachian regions of the United States. The Company pursues development drilling and exploitation projects, acquisitions and, to a lesser extent, exploration of its extensive acreage position. All Appalachian assets are held through a 50% interest in a joint venture, Great Lakes Energy Partners L.L.C. (“Great Lakes”). Independent Producer Finance (“IPF”), a wholly owned subsidiary, provides financing to small oil and gas producers through the purchase of overriding royalty interests. Both Great Lakes and IPF are independently financed and IPF’s and Range’s proportionate share of Great Lakes’ assets and operations are consolidated in the Company’s financial statements. At December 31, 2000, the Company had 583.7 Bcfe of proved reserves, having a pre-tax present value of $2.0 billion based on constant prices of $26.80 per barrel and $9.77 per Mcf. The pre-tax present value based on average projected futures prices as if they would have been in effect on December 31, 2000 of $22.00 per barrel and $4.45 per Mcf would have been $814.3 million. The Company’s proved reserves are 73% natural gas by volume, 70% developed and 83% operated. At year-end, the Company’s properties had a reserve life index of 10.5 years. In addition, the Company owned 488,000 gross (219,000 net) acres of undeveloped leasehold.

#### History

Between 1988 and 1997, the Company actively pursued small acquisitions and the further development of its properties. The Company was consistently profitable and steadily increased its production and reserves. Between late 1997 and mid-1998, a series of large acquisitions were consummated which proved extremely disappointing. Production from the acquired properties fell more rapidly than anticipated and further development of the principal fields proved far less attractive than expected. In combination with a steep decline in energy prices which began in late 1997 and the substantial burden imposed by debt and fixed income securities taken on in connection with the purchases, the adverse impact on the Company’s operating results, balance sheet and stock price was severe.

In 1998 and 1999, sharp reductions in staff and capital budgets, sales of properties and the formation of Great Lakes allowed the Company to materially reduce debt and stabilize its financial position. However, production and reserves fell as a result of these actions. In the Great Lakes transaction, the single most significant step in the debt reduction effort, Range and FirstEnergy Corp. (“FirstEnergy”) contributed their Appalachian oil and gas properties and associated gas pipeline systems to a joint venture, forming one of the largest production companies in the region. To achieve equal ownership despite Range’s contribution of a disproportionate share of the proved reserves, the venture assumed $188.3 million of Range’s bank debt and FirstEnergy contributed $2.0 million of cash.

Faced with high leverage and significant concern from its banks, the Company moved aggressively to hedge its production as the oil and gas markets began to recover in late 1999. These hedges, which covered roughly 80% of the Company’s anticipated production through the third quarter of 2000, were designed to assure financial viability while the restructuring was completed. Given the continuing sharp rise in oil and gas prices throughout 2000, these hedges substantially limited the benefits to the Company of the price increases. While the Company has continued to hedge on a rolling twelve to eighteen month basis since that time, the rise in prices has permitted a substantial increase in the average price at which production is hedged, particularly since September 30, 2000. At year end 2000, the

Company had hedges in place on approximately 33.7 Bcfe of gas and 1 million barrels of oil at average prices of $4.07 per Mcf and $28.62 per barrel. These hedges cover approximately 64% and 7% of the Company's anticipated production on an Mcfe basis for 2001 and 2002, respectively.

In 2000, with the benefit of rising oil and gas prices, the Company began to gradually increase capital expenditures while keeping spending well below internal cash flow to allow the continued pay down of debt. Through these repayments and exchanges of common stock for fixed income securities, debt was again substantially reduced. Despite capital constraints, the Company managed to modestly increase production in the course of the year primarily by bringing proved non-producing reserves on stream. While production rose during the year, it fell 17% from the prior year level primarily due to the impact of the Great Lakes transaction in late 1999. By mid-year, the progress made in restructuring began to be recognized and the market for the Company's stock started to rebound. However, due to the lower capital expenditures the Company was unable to replace production and proved reserves fell 5.4% during the year.

In 2001, the Company expects to increase its capital budget by 46% to roughly $85 million. This should generate a continued increase in production and, through the increase in spending and a greater emphasis on developing unproved reserves, may permit reserve growth to resume. Finally, the benefits of sharply higher energy prices and reduced fixed charges should allow substantial profitability and a continuing reduction of debt. By year-end 2001, management believes leverage will have been reduced to a fully manageable level and that the Company will be well positioned to again pursue profitable long-term growth.

**Description of the Business**

*Strategy*

Between 1988 and 1997, assets grew from $7 million to $764 million as stockholders' equity increased from less than $1 million to $197 million. In 1998 and 1999, the Company incurred almost $200 million of losses from continuing disappointing results on a series of large acquisitions consummated between late 1997 and mid-1998 which led to a series of impairments. These losses materially reduced stockholders' equity and increased leverage ratios. The significant improvement in oil and gas prices since mid-1999 combined with the benefits of reduced costs allowed the Company to return to profitability in 2000. In 2001, the Company's goal is to continue to reduce debt while increasing capital expenditures. The 2001 capital budget should provide modest production growth and may permit a resumption of reserve growth.

At year end, the Company had over 2,100 proven development projects in inventory. Given current oil and gas prices and this development inventory, the Company believes it can achieve growth in reserves, production, cash flow and earnings over the next several years while further reducing debt. The Company currently anticipates spending $85 million on capital expenditures in 2001. The Company's approximately 488,000 gross (219,000 net) acre undeveloped leasehold position provides significant long-term exploration and development potential.

*Development.* Development projects include recompletions of existing wells, infill drilling and the installation of secondary recovery projects. Such projects are pursued within core areas where the Company has significant operational and technical experience. At December 31, 2000, 1,812 proven drilling locations and 318 proven recompletions were in inventory. In 2001, 236 development wells and 73 recompletions are planned.

*Exploration.* Onshore exploration projects cover 264,810 gross (102,098 net) acres. These projects target deeper horizons in existing fields as well as prospective fields in trend areas. Offshore exploration focuses on the shallow waters of the Gulf of Mexico where 3D seismic data covering 3.5 million contiguous acres is held. Range has offshore leases covering 145,889 gross (37,012 net) acres on which it has to date identified nine specific projects. The Company's exploration strategy is based on limiting risk by allocating no more than 10% to 15% of the capital budget to such projects. At times, other companies pay all or a disproportionate share of exploration costs to earn an interest in a project. The Company currently anticipates participating in up to 30 exploratory wells in 2001.

*Acquisitions.* After a two year period during which the Company entirely withdrew from the acquisition market, management expects to reactivate this effort in the latter part of 2001. At least initially, the focus will be on modest purchases of incremental interests in existing and adjacent properties. To the extent the acquisition effort is successfully reinitiated and capital constraints are reduced, a more substantial effort will be considered beginning in 2002.

**Development and Exploration**

In 2000, the Company spent $53.5 million on oil and gas related capital expenditures, an increase of 43% over that expended in 1999 (see Note 16 to the financial statements). Of this amount, $17.6 million was expended in the Southwest, $12.7 million in Appalachia and $23.2 million in the Gulf Coast. These expenditures were primarily focused on placing proved non-producing reserves on stream. They funded 56 recompletions, 178 development and 16 exploratory wells, minor lease acquisitions and seismic work. Exploration and development spending brought 28.3 Bcfe of proved non-producing reserves on stream and added a net 22.4 Bcfe of new reserves. Net reserves added during the year replaced 41% of production (see Note 20 to the financial statements).

*Development*

Development includes recompletions, infill drilling and to a lesser extent, installation of secondary recovery projects. As described below, the Company currently has 2,130 proven recompletion opportunities and drilling locations in inventory. Drilling prospects are geographically diverse and target a mix of oil and gas, generally at depths of less than 8,000 feet. Approximately 83% of the proved development locations are concentrated in ten fields covering 824,144 gross (445,928 net) acres. The Company believes that such large acreage blocks and concentration of to be drilled wells provides economies of scale, access to competitively priced field services and focused operating and technical expertise. The following table sets forth information pertaining to the proven development inventory at December 31, 2000.

| | Development Projects | | |
|---|---|---|---|
| | Recompletion Opportunities | Drilling Locations | Total |
| Southwest | 193 | 151 | 344 |
| Gulf Coast | 51 | 26 | 77 |
| Appalachia | 74 | 1,635 | 1,709 |
| Total | 318 | 1,812 | 2,130 |

*Exploration*

*Onshore.* The Company currently has 165 onshore exploration projects covering 264,810 gross (102,098 net) acres. Each project has multiple drilling prospects, some with several targeted formations. Given the current emphasis on debt reduction, only a limited amount of work will be done on these projects in 2001.

*Gulf of Mexico.* The Company has a 3D seismic database covering 700 contiguous blocks in the shallow waters of the Gulf, primarily offshore Louisiana. This database has been used to map geological trends within this 3.5 million acre area, identifying specific targets for further exploration. The Company's current offshore leasehold inventory totals only 25,000 gross (8,383 net) acres. To more fully exploit the 3D seismic database, it will be necessary to farm-in or lease significant additional acreage. To date, nine specific prospects have been identified. These prospects target Miocene formations at depths of 8,000 to 18,000 feet.

**Production**

Production revenue is generated through the sale of natural gas, crude oil and natural gas liquids (“NGL”) from properties owned directly or through partnerships and joint ventures. The Company receives additional revenue from royalties. While production is sold to a limited number of purchasers, only three account for more than 10% of oil and gas revenues. Management believes that the loss of any individual customer would not have a material adverse effect on the Company. Proximity to local markets, availability of competitive fuels and overall supply and demand are factors affecting the prices at which production can be marketed. Factors outside the Company’s control, such as international political developments, overall energy supply and demand, weather conditions, economic growth rates and other factors in the United States and world economies have had, and will continue to have, a significant effect on energy prices.

The following table sets forth production volumes, revenue and expense information for the past five years (in thousands, except average sales price and operating cost data).

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | **1996** | **1997** | **1998** | **1999** | **2000** |
| Production | | | | | |
| Gas (Mcf) | 21,231 | 38,409 | 45,193 | 50,808 | 41,039 |
| Crude oil (Bbl) | 1,018 | 1,371 | 2,175 | 2,247 | 2,035 |
| Natural gas liquids (Bbl) | 50 | 423 | 480 | 412 | 363 |
| Total (Mcfe) (a) | 27,639 | 49,173 | 61,123 | 66,762 | 55,428 |
| Revenues | | | | | |
| Gas | $47,629 | $101,217 | $105,509 | $108,115 | $118,977 |
| Crude oil | 19,912 | 24,967 | 26,119 | 33,075 | 47,414 |
| Natural gas liquids | 513 | 3,833 | 3,965 | 4,302 | 6,691 |
| Total | $68,054 | $130,017 | $135,593 | $145,492 | $173,082 |
| Average sales price (b) | | | | | |
| Gas (Mcf) | $ 2.24 | $ 2.64 | $ 2.33 | $ 2.13 | $ 2.90 |
| Crude oil (Bbl) | 19.56 | 18.21 | 12.01 | 14.72 | 23.30 |
| Natural gas liquids (Bbl) | 10.26 | 9.06 | 8.26 | 10.44 | 18.43 |
| Mcfe (a) | 2.46 | 2.64 | 2.22 | 2.18 | 3.12 |
| Operating cost (Mcfe) | | | | | |
| Direct costs | $ 0.69 | $ 0.57 | $ 0.57 | $ 0.58 | $ 0.59 |
| Severance and production taxes | 0.06 | 0.07 | 0.07 | 0.07 | 0.11 |
| Total | $ 0.75 | $ 0.64 | $ 0.64 | $ 0.65 | $ 0.70 |

(a) Oil and NGL are converted to Mcfe at a rate of 6 Mcf per barrel.
(b) Average sales prices are net of hedging, which reduced average oil and gas prices in 2000 by $4.85 and $0.81, respectively.

On an Mcfe basis, approximately 74% of the Company’s production is natural gas. Gas is sold to utilities, marketing companies and industrial users. Gas sales are made pursuant to various contractual arrangements including month-to-month, one to three-year contracts at fixed or variable prices and fixed prices for the life of the well. All contracts other than the fixed price contracts contain provisions for price adjustment, termination and other terms customary in the industry. Great Lakes sells 90% of its gas production to FirstEnergy based on closing prices on the New York Mercantile Exchange (“NYMEX”). The terms automatically renew for one-month periods through June 30, 2001. Oil is sold under contracts that can be terminated on 30 days notice. The price received is generally equal to a posted price set by major purchasers in the area. Oil purchasers are selected on the basis of price and service. In 2000, gas revenues totaled $119 million or 69% of oil and gas revenues while revenues from oil and natural gas liquids totaled $54 million. Oil and gas revenues in 2000 increased 19% over the prior year despite a 17% decline in production.

**Transportation, Processing and Marketing**

Transportation, processing and marketing revenues are comprised of fees for the transportation and processing of gas as well as oil and gas marketing income. Transportation, processing and marketing revenues decreased 32% in 2000 to $5.3 million primarily as a result of asset sales.

The Company’s gas transportation and processing assets include (i) 50% ownership in approximately 4,700 miles of gas pipelines in Appalachia held through Great Lakes and (ii) a number of smaller gathering systems associated with the Company’s producing properties. The Appalachian gathering systems transport a majority of Great Lakes’ gas production as well as third party gas to major trunklines and directly to end-users. Third parties who transport gas through the systems are charged a fee based on throughput. In the Southwest and Gulf Coast regions gas production is transported through a combination of Company-owned and third party gathering systems. The Company is typically charged a fee based on throughput in order to transport its gas through third party systems.

The Company markets its own gas production and manages the impact of price fluctuations through hedging. Only 2% of gas production is currently sold pursuant to fixed price contracts at prices ranging from $1.25 to $4.73 per Mcf (averaging $2.98 per Mcf). The remaining 98% of gas production is sold at market (generally NYMEX) related prices.

**Hedging Activities**

The Company regularly enters into hedging agreements to reduce the impact of fluctuations in oil and gas prices. All such contracts are entered into solely to hedge prices and to limit volatility. The Company’s current policy is to hedge between 50% and 75% of its production on a rolling twelve to eighteen month basis. At December 31, 2000, hedges were in place covering 33.7 Bcf of gas and 1.0 million barrels of oil at prices ranging from $2.84 to $6.78 per Mmbtu (averaging $4.07) and from $26.96 to $33.71 per barrel (averaging $28.62). While these transactions have no carrying value, their fair value, represented by the estimated amount that would be required to terminate them, was a net loss of $72.1 million at December 31, 2000. Due to the decline in commodity prices, particularly natural gas, subsequent to year end, the fair market value of these hedge transactions was a net loss of $54.5 million at February 28, 2001. The contracts expire monthly through December 2002 and cover approximately 64% of anticipated 2001 production and 7% of 2002 production. Gains or losses on hedging transactions are determined as the difference between the contract price and a reference price, generally closing prices on the NYMEX. Transaction gains and losses are determined monthly and are included in oil and gas revenues in the period the hedged production is sold. Net gains (losses) relating to these derivatives in 1998, 1999 and 2000 approximated $3.1 million, $(10.6) million and $(43.2) million, respectively. Effective January 1, 2001, the gains (losses) in these hedging positions will be recorded at fair value on the Company’s balance sheet as Other Comprehensive Income (Loss), a component of Stockholders’ Equity.

In June 2000, the Company repriced 4.1 Bcf of natural gas hedges from an average price of $2.59 to $3.00 per Mmbtu. In exchange, the Company hedged an average of 22,700 Mmbtu per day from April 2001 through March 2002 at an average price of $3.20 per Mmbtu. While the Company’s payment requirement for the repriced hedges was affected, the $6.0 million of estimated net losses on the original hedges were recorded in the periods in which they would have been recorded under generally accepted accounting principles. A deferred loss and associated liability of $6.0 million were recorded on the Balance Sheet at June 30, 2000, of which $665,000 and $945,000 remained at December 31, 2000, respectively. The imputed interest cost of the repricing was $168,000. See Note 7 for a summary of the Company's hedge position at December 31, 2000.

**Independent Producer Finance ("IPF")**

IPF provides capital to small oil and gas producers to finance acquisition and development projects in exchange for term overriding royalty interests. The overrides are dollar-denominated and calculated to provide a contractual rate of return that typically ranges between 15% and 25%. Almost all of the advances are for less than $5 million and most are for $1 million or less. IPF funds itself through a combination of internal cash flow and bank borrowings. At December 31, 2000, IPF's portfolio included 45 transactions having an aggregate book value of $48.9 million (net of $15.3 million of valuation allowances). The portfolio balance declined 25% from December 31, 1999 primarily due to $24.8 million of repayments received during 2000. The reserves underlying IPF's royalty interests are not included in Range's consolidated reserve disclosure.

IPF provides valuation allowances against advances which may not be recoverable. These allowances reduce reported revenues. During early 2000, IPF provided $603,000 in additional allowances. However, because of higher product prices and growing cash receipts, IPF reversed $1.9 million of previously recorded allowances during the year. Accordingly, reported revenues increased a net $1.3 million, from $8.7 million to $10.0 million. IPF expenses include general and administrative costs and interest expense, which totaled $1.5 million and $3.4 million, respectively, in 2000. At current commodity prices, the Company believes that IPF's valuation allowances are adequate.

IPF has three petroleum engineers and geologists with an average of 18 years of experience who identify and evaluate projects. The staff is responsible for defining transaction risk, assessing reserve coverage and negotiating terms. Transactions are structured to minimize risk by focusing on asset coverage and taking direct title to the royalty interests. As dollar-denominated royalties, the transactions leave a portion of the commodity price risk with the producer. However, when extreme price declines occur, as they did in 1998 and 1999, IPF is exposed to substantial losses.

IPF provides capital to parties who are generally ignored by traditional financial institutions. These producers are typically denied access to financing because: (i) they are too small to access the public securities markets; (ii) private equity and debt financing is too restrictive and expensive; and (iii) few commercial banks are interested in small energy loans as consolidation in the banking industry has raised the size threshold for lending. IPF's portfolio decreased in 2000 as a limited number of fundings were more than offset by principal repayments. IPF expects demand for funding to rise as acquisition and divestiture activity accelerates and further consolidation in the banking industry reduces the availability of bank financing for small transactions. IPF's bank debt is non-recourse to Range.

IPF investments involve the purchase of a term overriding royalty interest pursuant to which it receives a specified share of revenues from specific properties. The producer's obligation is non-recourse unless he fails to operate prudently, there is title failure and in certain other circumstances. Consequently, IPF's success is based on its ability to accurately estimate reserves underlying its royalty, the prices at which the production will be sold, and the operator's ability to recover the reserves on a timely basis. Because the override is considered a property interest, if a producer goes bankrupt, IPF's interest should be beyond the reach of creditors. If a creditor, the producer as debtor-in-possession or a trustee in a bankruptcy proceeding were to argue successfully that the transaction should be characterized as a loan, IPF may have only a creditor's claim for repayment. IPF's ownership in these production payments is a non-operated interest. While IPF is unlikely to be exposed to liabilities associated with direct working interests, such as environmental matters, personal injuries or death and property damage, such events could result in a loss of IPF's economic interest in the properties. The producer's obligation to deliver a specified share of revenues to IPF is subject to the ability of the burdened reserves to produce such revenues. As a result, IPF bears the risk that revenues will not be sufficient to amortize its investment or provide an acceptable return.

IPF was acquired in 1998. The following table summarizes IPF's historical investments:

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | **1996** | **1997** | **1998** | **1999** | **2000** |
| Total advances ($000) | $19,100 | $40,150 | $45,822 | $4,259 | $6,985 |
| Number of advances | 27 | 39 | 75 | 30 | 26 |
| Average advance ($000) | $ 707 | $ 1,029 | $ 611 | $ 142 | $ 269 |

## Interest and Other

The Company earns interest on cash balances and various receivables. However, interest and other income in 2000 was comprised principally of losses on property sales. The Company expects to continue to sell non-strategic properties. Interest and other income in 2000 amounted to $(702,000), representing (0.4)% of revenues.

## Competition

The Company encounters substantial competition in acquiring oil and gas leases, marketing its production, securing personnel and conducting drilling and field operations. Competitors in development, exploration, acquisitions and production include the major oil companies as well as numerous independents, individual proprietors and others. Many competitors have financial and other resources substantially exceeding those of the Company. Therefore, competitors may be able to pay more for desirable leases and to evaluate, bid for and purchase a greater number of properties or prospects than the financial or personnel resources of the Company permit. The ability of the Company to replace and expand its reserve base will depend on its ability to identify and acquire suitable producing properties and prospects for future drilling.

Acquisitions have generally been financed through the issuance of debt and equity securities and internally generated cash flow. There is competition for capital to finance oil and gas projects. The ability of the Company to obtain financing on satisfactory terms is uncertain and can be affected by numerous factors beyond its control. The inability of the Company to raise external capital in the future could have a material adverse effect on its business.

## Governmental Regulation

The Company's operations are affected in varying degrees by federal, state and local laws and regulations. In particular, oil and gas production and related operations are or have been subject to price controls, taxes and other laws and regulations. Failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the Company's cost of doing business and affects its profitability. Although the Company believes it is in substantial compliance with all applicable laws and regulations, because such laws and regulations are frequently amended or reinterpreted, the Company is unable to precisely predict the future cost or impact of complying.

## The Restructuring

A series of significant acquisitions financed principally with debt and convertible securities were completed between late 1997 and mid-1998. Due to the poor performance of the acquired properties compounded by a decline in oil and gas prices which began in late 1997, the Company was forced to take a number of steps. These included a workforce reduction, a significant decrease in capital expenditures, the sale of assets, the formation of Great Lakes and the exchange of common stock for fixed income securities. Since year-end 1998, these initiatives have reduced parent company bank debt from over $365 million to $89.9 million. Total debt (including trust preferred) has been reduced 37% to $458.1 million. While management believes these steps have stabilized the Company's financial position, debt remains too high. For the Company to return to its historical posture of consistent profitability and growth, further reductions in debt are believed necessary. The Company expects to utilize excess cash flow to retire debt and to continue to exchange common stock or other equity-linked securities for fixed income securities. While the Company hopes to reacquire the fixed income securities at a discount to face value, existing stockholders will be substantially diluted if a material portion of the fixed income securities are exchanged. The extent of dilution will depend on a number of factors, including the number of shares issued, the price at which stock is issued or newly issued securities are convertible into common stock and the price at which fixed income securities are reacquired. While such exchanges reduce existing stockholders' proportionate ownership, management believes such exchanges enhance the Company's financial flexibility and could increase the market value of its common stock.

While the Company currently believes it has sufficient liquidity and cash flow to meet its obligations, a material drop in oil and gas prices or a reduction in production and reserves would reduce the ability to fund capital expenditures, reduce debt and meet financial obligations.

**Environmental Matters**

The Company's operations are subject to stringent federal, state and local laws governing the discharge of materials into the environment or otherwise relating to environmental protection. Numerous governmental departments such as the Environmental Protection Agency ("EPA") issue regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and pipeline, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent pollution from former operations such as plugging abandoned wells, and impose substantial liabilities for pollution resulting from operations. In addition, these laws, rules and regulations may restrict the rate of production. The regulatory burden on the oil and gas industry increases the cost of doing business and affects profitability. Changes in environmental laws and regulations occur frequently, and changes that result in more stringent and costly waste handling, disposal or clean-up requirements could adversely affect the Company's operations and financial position, as well as the industry in general. Management believes the Company is in substantial compliance with current applicable environmental laws and regulations. The Company has not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. The Company did not have any material capital expenditures in connection with environmental matters in 2000, nor does it anticipate that such expenditures will be material in 2001.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed of or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damages allegedly caused by the release of hazardous substances or other pollutants into the environment. Furthermore, although petroleum, including crude oil and natural gas, is exempt from CERCLA, at least two courts have ruled that certain wastes associated with the production of crude oil may be classified as "hazardous substances" under CERCLA and that such wastes may become subject to liability and regulation under CERCLA. State initiatives to further regulate the disposal of oil and gas wastes are pending in certain states and these initiatives could have a significant impact on the Company.

The Federal Water Pollution Control Act ("FWPCA") imposes restrictions and strict controls regarding the discharge of produced waters and other oil and gas wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters. The FWPCA and analogous state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other hazardous substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages. State water discharge regulations and the federal National Pollutant Discharge Elimination System general permits applicable to the oil and gas industry generally prohibit the discharge of produced water, sand and some other substances into coastal waters. The cost to comply with zero discharges mandated under federal and state law have not had a material adverse impact on the Company's financial condition and results of operations. Some oil and gas exploration and production facilities are required to obtain permits for their storm water discharges. Costs may be incurred in connection with treatment of wastewater or developing storm water pollution prevention plans.

The Resources Conservation and Recovery Act ("RCRA"), as amended, generally does not regulate most wastes generated by the exploration and production of oil and gas. RCRA specifically excludes from the definition of hazardous waste "drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy." However, these wastes may be regulated by the EPA or state agencies as solid waste. Moreover, ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils, are regulated as hazardous wastes. Although the costs of managing solid hazardous waste may be significant, the Company does not expect to experience more burdensome costs than similarly situated companies.

The U.S. Oil Pollution Act ("OPA") requires owners and operators of facilities that could be the source of an oil spill into "waters of the United States" (a term defined to include rivers, creeks, wetlands and coastal waters) to adopt and implement plans and procedures to prevent any spill of oil into any waters of the United States. OPA also requires affected facility owners and operators to demonstrate that they have at least $35 million in financial resources to pay for the costs of cleaning up an oil spill and compensating any parties damaged by an oil spill. Substantial civil and criminal fines and penalties can be imposed for violations of OPA and other environmental statutes.

Stricter standards in environmental legislation may be imposed on the oil and gas industry in the future. For instance, legislation has been proposed in Congress from time to time that would reclassify certain oil and gas exploration and production wastes as "hazardous wastes" and make the waste subject to more stringent handling, disposal and clean-up restrictions. If such legislation were enacted, it could have a significant impact on the Company's operating costs, as well as the industry in general. Compliance with environmental requirements generally could have a material adverse effect on the capital expenditures, earnings or competitive position of the Company. Although the Company has not experienced any material adverse effect from compliance with environmental requirements, no assurance may be given that this will continue.

**Risk Factors and Cautionary Statement for purposes of the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995**

Certain information included in this report, other materials filed or to be filed by the Company with the Securities and Exchange Commission ("SEC"), as well as information included in oral statements or other written statements made or to be made by the Company contain or incorporate by reference certain statements (other than statements of historical fact) that constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. When used herein, the words "budget," "budgeted," "assumes," "should," "goal," "anticipates," "expects," "believes," "seeks," "plans," "estimates," "intends," or "projects" and similar expressions that convey the uncertainty of future events or outcomes are intended to identify forward-looking statements. Where any forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from actual results and the difference between assumed facts or bases and the actual results could be material, depending on the circumstances. It is important to note that our actual results could differ materially from those projected by such forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable and such forward-looking statements are based upon the best data available at the date this report is filed with the SEC, we cannot assure you that such expectations will prove correct. Factors that could cause our results to differ materially from the results discussed in such forward-looking statements include, but are not limited to, the following: production variance from expectations, volatility of oil and gas prices, hedging results, the need to develop and replace reserves, the substantial capital expenditures required to fund operations, exploration risks, environmental risks, uncertainties about estimates of reserves, competition, litigation, government regulation, political risks, and our ability to implement our business strategy. All such forward-looking statements in this document are expressly qualified in their entirety by the cautionary statements in this paragraph.

With the previous paragraph in mind, you should consider the following important factors that could cause actual results to differ materially from those expressed in any forward-looking statement made by the Company or on its behalf.

*Common shareholders will be diluted if additional shares are issued*

The Company has filed shelf registration statements which allow it to issue additional common stock and has exchanged common stock for its fixed income securities over the past two years. In 1999, 2000 and early 2001, the Company exchanged common stock for 5 3/4% trust convertible preferred securities, convertible debentures and $2.03 convertible preferred stock. The exchanges were made based on the relative market value of the common stock and the convertible securities at the time of the exchange, incorporating negotiated terms ranging from a 6% discount to a 7% premium. The convertible securities were acquired at discounts to their face value ranging from 10% to 63%. During 2000, $25.0 million of trust preferred, $13.8 million of 6% convertible debentures and $23.2 million of $2.03 convertible preferred stock was acquired in exchange for common stock. See Notes 6 and 9 to the financial statements. While the exchanges reduce interest expense, dividends and future repayment obligations, the larger number of common shares outstanding have a dilutive effect on existing shareholders.

The Company continues to review alternatives to further strengthen its balance sheet and to retire debt and convertible securities. The Company expects any alternative to involve the prospective issuance of a large number of shares of common stock. Therefore, such alternatives will tend to dilute current shareholders. The Company expects to continue to exchange common stock or other equity linked securities for its fixed income securities. While the Company anticipates reacquiring fixed income securities at a discount to their face value, existing stockholders will be substantially diluted if material portions of the fixed income securities are exchanged. The extent of dilution will depend on various factors, including the number of shares issued, the price at which newly issued securities are convertible into common stock and the price at which fixed income securities are reacquired. While such exchanges reduce existing stockholders' proportionate ownership, management believes such exchanges enhance the Company's financial flexibility and could increase the market value of its common stock. The Company's ability to consummate exchanges and the terms of the exchanges is dependent on a number of factors beyond its control, such as the level of various interest rates, the willingness of other parties to engage in transactions, state and federal regulations covering such transactions and capital market conditions.

*Dividends restrictions*

Restrictions on the payment of dividends and other restricted payments as defined are imposed under the Company's bank credit agreements and the 8.75% senior subordinated notes. No common dividends may be paid under the current bank agreement. Partially in response to these restrictions, a new $2.03 Convertible Exchangeable Preferred Stock Series D was authorized in September 2000. The Series D had terms substantially identical to the previously outstanding Series C except that dividends could be paid in common stock. In November 2000, 523,140 shares of Series C were exchanged for Series D on a one-for-one basis. In December 2000, 323,140 shares of Series D were exchanged for common stock and the Company elected to pay fourth quarter 2000 Series D dividends in common stock. Fourth quarter 2000 dividends paid on the Series C amounted to only $10,000. Subsequent to year-end, all remaining shares of Series D and all but 8,235 shares of Series C were exchanged for common stock. Dividends on the remaining preferred stock amount to less than $17,000 per annum.

The terms of the 8.75% senior subordinated notes limit restricted payments (including dividends) to the greater of $20 million or a formula based on earnings since the issuance of the notes. Given the Company's losses over the past few years, the formula provides no availability. Therefore, the Company must rely on the $20 million basket. At December 31, 2000, $4.9 million of the $20 million basket remained available.

*Oil and gas prices are volatile, which can adversely affect cash flow available for reinvestment*

The oil industry is highly cyclical and prices for oil and gas are volatile. Historically, the industry has experienced severe downturns characterized by oversupply and/or weak demand. Many factors affect oil and gas prices including general economic conditions, consumer preferences, discretionary spending levels, interest rates and the availability of capital to the industry. In 1998 and early 1999, oil and gas prices fell substantially, which contributed to the substantial losses reported by the Company in those years. At present, oil and gas prices are at levels substantially above their historical norm. Decreases in oil and gas prices from current levels could adversely affect the Company's revenues, results of operations, cash flows and proved reserves. Significant and prolonged price decreases could have a materially adverse effect on the Company's operations and limit its ability to fund capital expenditures. The Company has entered into hedging agreements covering approximately 64% and 7% of its anticipated production on an Mcfe basis for 2001 and 2002, respectively.

*Hedging activities expose us to certain risks*

We enter into hedging arrangements covering a portion of our future oil and gas production to limit volatility and provide more predictable cash flow. Hedging instruments used include fixed price swaps and have at times included or may include collars, puts and options on futures. While hedging limits our exposure to adverse price movements, hedging may limit the benefit of price increases and is subject to a number of risks, including the risk the other party to the hedge will not perform.

*Estimates of oil and gas reserves may change; we may not replace production*

The information on proved oil and gas reserves included in this document are simply estimates. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment, assumptions used regarding quantities of oil and gas in place, recovery rates and future prices for oil and gas. Actual prices, production, development expenditures, operating expenses and quantities of recoverable oil and gas reserves will vary from those assumed in our estimates, and such variances may be significant. If the assumptions used to estimate reserves later prove incorrect in any way, the actual quantity of reserves and future net cash flow could be materially different from the estimates used herein. In addition, results of drilling, testing and production along with changes in oil and gas prices may result in substantial upward or downward revisions.

Without success in exploration, development or acquisitions, our reserves, production and revenues from the sale of oil and gas will decline over time. Exploration, the continuing development of our properties and acquisitions all require significant expenditures as well as expertise. If cash flow from operations proves insufficient for any reason, we may be unable to fund exploration, development and acquisitions at levels we deem advisable.

*Our oil and gas properties' carrying value may be written down*

Accounting rules require that the carrying value of oil and gas properties be periodically reviewed for possible impairment. An "impairment" is recognized when the book value of a proven property is greater than the expected undiscounted future cash flows from that property. We may be required to write down the carrying value of a property based on oil and gas prices at the time of the impairment review, as well as a continuing evaluation of development results, production data, economics and other factors. While an impairment charge does not impact cash or cash flow from operating activities, it reduces earnings, increases leverage ratios and reflects the long-term ability to recover a prior investment.

Based primarily on the poor performance of certain properties acquired between late-1997 and mid-1998 and significantly decreased oil and gas prices, we recorded impairments of $197 million in 1998 and $27 million in 1999. For a further discussion of our accounting policies with respect to oil and gas properties, see Note 1 to the Consolidated Financial Statements.

*We could incur substantial environmental liabilities*

Our industry is subject to numerous federal, state and local laws and regulations relating to the environment. We may incur significant costs and liabilities in complying with existing or future environmental laws and regulations. It is possible that increasingly strict environmental laws, regulations and enforcement policies or claims for damages to property, employees, other persons and the environment resulting from current or discontinued operations, could result in substantial costs and liabilities in the future. For additional information concerning environmental matters, see the "Environmental Matters" section included in this report.

*Our activities involve operating hazards and uninsured risks*

While we maintain insurance against certain of the risks associated with our operations, including, but not limited to, explosion, pollution and fires, an event against which we are not fully insured could have a significant negative effect on our business. Such occurrences could include title defects on properties, lost equipment in drilling operations when the drilling contractor is not responsible for such loss, costs to redrill wells due to down hole equipment and casing failures, and property damage caused over a period of time not covered by standard industry insurance policies.

We maintain insurance in amounts and areas of coverage normal for a company of our size and industry. These include, but are not limited to, workers' compensation, employers' liability, automotive liability and general liability. In addition, umbrella liability and operator's extra expense policies are maintained. All such insurance is subject to normal deductible levels. We do not insure against all risks associated with our business either because insurance is unavailable or because we elect not to insure due to prohibitive cost or other considerations.

Individuals or companies who feel the Company or those acting on its behalf damaged them physically or financially, have the right under the law to seek recovery in court. In today's legal climate, the likelihood of suits continues to increase. As verdicts or judgments are so uncertain, the Company may elect to settle claims. Settlements may not be covered by insurance and costs might have to be borne solely by the Company. Even when the Company elects to contest a claim, it may be held liable by the courts. Often, the cost of defending oneself or one's rights cannot be recovered from the other parties even if you prove successful and the costs must be borne solely by the Company. Such costs and settlements could have a material effect on the Company's financial position. See Item 3 "Legal Proceedings" included in this report and Note 8 to Consolidated Financial Statements as to certain proceedings and contingencies.

*We are subject to financing and interest rate exposure risks*

Our business and operating results can be harmed by factors such as the availability and cost of capital, increases in interest rates, changes in the tax rates, market perceptions of the oil and gas industry or the Company, or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue opportunities and place us at a competitive disadvantage. At December

31, 2000, the Company had a portion of its borrowings subject to interest rate swap agreements. See Note 7 to the financial statements.

*We face considerable competition*

We face competition in every aspect of our business, including, but not limited to, acquiring reserves, leases, obtaining goods, services, and employees needed to operate and manage the Company, and marketing oil and gas. Competitors include multinational oil companies, independent production companies and individual producers and operators. Many of our competitors have greater financial and other resources than we do.

*The oil industry is subject to extensive regulation*

The oil industry is subject to various types of regulations in the United States by local, state and federal agencies. Legislation affecting the industry is under constant review for amendment or expansion, frequently increasing the regulatory burden. Numerous departments and agencies, both state and federal, are authorized by statute to issue rules and regulations binding on the industry and participants in it. Compliance with such rules and regulations is often difficult and costly and may carry substantial penalties for non-compliance. As the regulatory burden on the industry increases, the cost of complying affects profitability. Generally these burdens do not appear to affect the Company to any greater or lesser extent than other companies in the industry with similar types and quantities of properties in the same areas of the country. While we are a party to several regulatory proceedings before governmental agencies arising in the ordinary course of business, we do not believe that their outcome will have a material adverse effect on our operations or financial condition.

*Our high fixed charge burden could impact our liquidity, profitability and cash flow*

The Company pays significant fixed charges associated with its bank debt, 8.75% senior subordinated notes, 6% convertible debentures, the bank debt of its subsidiaries and 5.75% trust preferred. At December 31, 2000, the face value of these obligations totaled $458 million and the associated fixed charges, based on rates in effect at that date totaled $36.3 million a year. In addition, these obligations have certain requirements that the Company must meet to avoid the acceleration of the maturity of these instruments. See Note 6 to the Consolidated Financial Statements for their stated maturities. The acceleration of the maturity of one or more of such obligations could have a material adverse effect on the Company.

The Company’s significant debt burden could have other important consequences such as, but not limited to, requiring the sale of assets at unfavorable prices, the impact of an increase in interest rates which would increase financing costs and limit capital available for developing and acquiring new properties, limit the ability to raise capital in the equity and/or debt markets, preclude financing options available to less leveraged companies, and make the Company more vulnerable to losses during periods of low oil and gas prices.

*Risks associated with IPF*

IPF purchases term overriding royalty interests through which it receives an agreed upon share of revenues from certain properties. The producer’s obligation to deliver revenues to us is non-recourse. Consequently, IPF can only recover its investment and a return through revenues from those properties. These revenues are subject to our ability to accurately estimate reserves and production rates and the operator’s ability to produce and recover these reserves. In summary, IPF bears the risk that future revenues it receives will be insufficient to amortize the price paid for its overrides or to provide an acceptable return.

*Acquisitions are subject to numerous risks*

It generally is not feasible to review in detail every individual property acquired. Ordinarily, a review is focused on higher-valued properties. However, even a detailed review of all properties and records may not reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not always inspect every well we acquire, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is performed. In late 1997 and 1998, a series of acquisitions were consummated which proved extremely unsuccessful. Ongoing results showed the potential of the properties was far less than our engineering and geological review, as well as a review by one of our independent petroleum engineering firms, had suggested.

*Our Chairman has an interest in another oil and gas company that could compete with us*

Our Chairman also serves as the Chairman and Chief Executive Officer of Patina Oil & Gas Corporation ("Patina"), a publicly traded oil and gas company in which he is a significant investor. He is also an officer, director and/or significant investor in several other public and private companies engaged in various aspects of the energy industry. We currently have no business relationship with any of these companies, none of them owns our securities nor do we hold any of theirs. Historically, no material conflict has arisen with regard to these companies. However, conflicts of interests may arise. Board policies are in place that require Mr. Edelman, along with all other officers and directors, to give us notification of any potential conflicts that arise. However, we cannot assure you that we will not compete with one or more of these companies, particularly for acquisitions, or encounter other conflicts of interest in the future.

*Success depends on key members of our management*

The Company's success is highly dependent on its senior management personnel, none of who are currently subject to employment contracts. The loss of one or more of these individuals could have a material adverse effect on the Company.

**Employees**

As of January 1, 2001, the Company had 139 full time employees, 49 of whom were field personnel. None are covered by a collective bargaining agreement. Management believes that its relationship with employees is good.

## ITEM 2. PROPERTIES

On December 31, 2000, the Company held working interests in 9,649 gross (4,790 net) productive wells and royalty interests in an additional 436. Including its 50% share of Great Lakes' reserves, its properties contained, net to its interest, estimated proved reserves of 427.7 Bcf of gas and 26.0 million barrels of oil and NGL or a total of 583.7 Bcfe.

### Proved Reserves

The following table sets forth estimated proved reserves over the past five years.

| | December 31, | | | | |
|---|---|---|---|---|---|
| | **1996** | **1997** | **1998** | **1999** | **2000** |
| Natural gas (Mmcf) | | | | | |
| Developed | 207,601 | 369,786 | 436,062 | 299,436 | 305,796 |
| Undeveloped | 87,993 | 204,632 | 197,255 | 144,345 | 121,871 |
| Total | 295,594 | 574,418 | 633,317 | 443,781 | 427,667 |
| Oil and NGL (Mbbls) | | | | | |
| Developed | 10,703 | 14,971 | 19,649 | 17,884 | 17,215 |
| Undeveloped | 3,972 | 14,803 | 7,480 | 10,933 | 8,787 |
| Total | 14,675 | 29,774 | 27,129 | 28,817 | 26,002 |
| Total (Mmcfe) (a) | 383,644 | 753,062 | 796,091 | 616,685 | 583,680 |
| % Developed | 70.9% | 61.0% | 70.0% | 66.0% | 69.7% |

(a) Oil and NGL are converted to Mcfe at a rate of 6 Mcf per barrel.

At year end 2000, the Company engaged the following independent petroleum consultants to evaluate its reserves: H.J. Gruy and Associates, Inc. (Southwest), DeGolyer and MacNaughton (Southwest and Gulf Coast), and Wright and Company, Inc. (Appalachia). These engineers were employed primarily based on their geographic expertise as well as their history in engineering certain properties. At December 31, 2000, these consultants collectively evaluated approximately 80% of the proved reserves set forth above. The remainder were evaluated by the internal engineering staff. All estimates of oil and gas reserves are subject to significant uncertainty.

The following table sets forth the estimated future net revenues from proved reserves and the present value of those revenues in millions over the past five years.

| | December 31, | | | | |
|---|---|---|---|---|---|
| | **1996** | **1997** | **1998** | **1999** | **2000** |
| Future net revenues | $941 | $1,276 | $1,020 | $1,013 | $3,764 |
| Present Value | | | | | |
| Pre-tax | 492 | 632 | 555 | 556 | 1,964 |
| After tax | 351 | 511 | 517 | 503 | 1,506 |

Future net revenues represent future revenues from the sale of proved reserves net of production and development costs (including production and ad valorem taxes and operating expenses). Such calculations, prepared in accordance with SFAS No. 69, “Disclosures about Oil and Gas Producing Activities,” are based on costs and prices in effect at December 31, 2000. Average product prices at December 31, 2000 were $24.95 per barrel of oil, $14.58 per barrel for natural gas liquids, and $9.46 per Mcf of gas using benchmark NYMEX prices of $26.80 per barrel and $9.77 per Mmbtu. There can be no assurance that the proved reserves will be produced within the periods indicated or that prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties. No estimates of reserves have been filed with or included in reports to another federal authority or agency since year-end.

**Significant Properties**

The Company’s proved reserves at December 31, 2000 were concentrated in three regions, Southwest, Gulf Coast and Appalachia. The Southwest is divided into the Permian and the Midcontinent divisions. The Appalachian properties represent the Company’s 50% ownership in Great Lakes. At year-end, the Company’s properties included working interests in 9,857 gross (4,788 net) productive oil and gas wells and royalty interests in 436 additional wells. The Company also held interests in 487,688 gross (219,457 net) undeveloped acres. The following table sets forth summary information with respect to estimated proved reserves at December 31, 2000.

| | Pre-tax Present Value | | | | |
|---|---|---|---|---|---|
| | Amount (In thousands) | % | Oil & NGL (Mbbls) | Natural Gas (Mmcf) | Total (Mmcfe) |
| Southwest | | | | | |
| Permian | $ 445,251 | 23 | 16,600 | 75,071 | 174,671 |
| Midcontinent | 244,862 | 12 | 817 | 53,924 | 58,826 |
| Subtotal | 690,113 | 35 | 17,417 | 128,995 | 233,497 |
| Gulf Coast | 559,480 | 28 | 2,386 | 95,207 | 109,523 |
| Appalachia | 714,665 | 37 | 6,199 | 203,465 | 240,660 |
| Total | $1,964,258 | 100 | 26,002 | 427,667 | 583,680 |

*Southwest Region*

The Southwestern properties are situated in the Permian and Val Verde Basins of west Texas, the Texas panhandle, the East Texas Basin and the Anadarko Basin of western Oklahoma. Reserves in this region represented 40% by volume and 35% by value of total proved reserves at December 31, 2000. Proved reserves totaled 233 Bcfe, of which 55% was gas. At December 31, 2000, the Southwest Region properties had a development inventory of 193 proven recompletions and 151 drilling locations. Acreage owned by the Southwest Region at December 31, 2000 included 264,719 gross (189,692 net) developed acres and 54,025 gross (41,074 net) undeveloped acres. During 2000, 29 development wells (19.7 net) were drilled, of which 25 (16.8 net) were productive. Two exploratory wells (0.6 net) were drilled, of which none were productive.

*Permian.* The Permian properties, located in the Permian and Val Verde Basins of west Texas, contained 175 Bcfe of proved reserves at year end. These reserves represented 30% by volume and 23% by value of total proved reserves and were 57% oil and NGL. In the fourth quarter of 2000, net production averaged 4,244 barrels of oil and NGL and 19.1 Mmcf of gas per day, or 44.6 Mmcfe per day in total. Producing wells total 1,256 (1,129 net), of which the Company operates approximately 93%. Major producing areas include Sonora, Sterling and Big Lake/Fuhrman-Mascho/Powell Ranch. The Oakridge and Frances Hill fields in the Sonora area produce from multiple deltaic channel Canyon sandstones at depths of 2,600 to 6,000 feet. At Sterling, gas production is derived from Canyon/Cisco sub-marine sand deposits at

4,000 to 8,000 foot depths, while oil production comes from Silurian Fusselman carbonates at 8,200 to 10,000 feet. The Big Lake/Fuhrman-Mascho/Powell Ranch area produces primarily oil from the San Andres/Grayburg formations at depths ranging from 2,500 feet to 4,600 feet and from the Wolfcamp formation at a depth of 8,000 to 9,000 feet. At December 31, 2000, the Permian division had a development inventory of 155 proven recompletions and 135 proven drilling locations. Acreage owned by the Permian division at December 31, 2000 included 66,919 gross (64,892 net) developed acres and 48,325 gross (37,374 net) undeveloped acres. During 2000, eleven development wells (6.1 net) were drilled, all of which were productive. One exploratory well (0.5 net) was drilled, which was dry.

*Midcontinent.* The Midcontinent properties, located in the Anadarko Basin of western Oklahoma and the Texas panhandle, held proved reserves of 59 Bcfe at December 31, 2000. These reserves, representing 10% by volume and 12% by value of total proved reserves were 92% gas. Of the 311 gross (197 net) wells in the division, 94% are operated. The division’s largest property is the Okeene Field, which includes 184 operated wells. In the fourth of quarter 2000, net production averaged 149 barrels of oil and 12.0 Mmcf of gas per day or 12.9 MMcfe per day in total. The properties produce from a variety of sands and carbonates in both structural and stratigraphic traps on the Hunton, Red Fork, Mississippi, Spring, and Morrow formations at 6,000 to 12,000 foot depths. At December 31, 2000, the Midcontinent division had a development inventory of 38 proven recompletions and 16 proven drilling locations. Acreage owned by the Midcontinent division at December 31, 2000 included 197,800 gross (124,800 net) developed acres and 5,700 gross (3,700 net) undeveloped acres. During 2000, 18 development wells (13.6 net) were drilled, of which 14 (10.7 net) were productive. One exploratory well (0.1 net) was drilled, which was dry.

*Gulf Coast Region*

The Gulf Coast properties include onshore reserves in south Texas, Louisiana and Mississippi, as well as offshore reserves in the shallow waters of the Gulf of Mexico. The properties contained 110 Bcfe of proved reserves at December 31, 2000, or 19% by volume and 28% by value of total proved reserves and were 87% gas. In the fourth quarter of 2000, net production averaged 1,261 barrels of oil and 54.9 Mmcf of gas per day or 62.5 Mmcfe per day in total. Major onshore fields include Alta Mesa and Oakvale. These fields produce from the Frio, Vicksburg, and Hosston formations at depths ranging from 1,000 to 16,000 feet. In total, the onshore properties include 59 wells (46 net), of which 86% are operated. The properties in the Gulf of Mexico include interests in 50 platforms in water depths ranging from 20 to 400 feet, none of which are operated. The entire Gulf Coast region is characterized by relatively complex geology, multiple producing horizons and substantial exploitation and exploration potential. At December 31, 2000, the Gulf Coast region had a development inventory of 51 proven recompletions and 26 proven drilling locations. Acreage owned by the Gulf Coast Region at December 31, 2000 included 154,542 gross (41,885 net) developed acres and 85,633 gross (18,379 net) undeveloped acres. During 2000, eight development wells (4.0 net) were drilled, of which seven (3.0 net) were productive. Five exploratory wells (1.4 net) were drilled, of which four (1.3 net) were productive.

*Appalachian Region*

At December 31, 2000, the Company’s 50% ownership in Great Lakes represented a net 241 Bcfe of proved reserves, or 41% by volume and 37% by value of total proved reerves. The reserves are attributable to 7,951 gross wells (3,371 net) located in Pennsylvania, Ohio, West Virginia, New York and Michigan. Great Lakes operates 94% of the wells. The reserves are 85% gas and produce principally from the Upper-Devonian, Medina, Clinton, Knox and Oriskany formations at depths ranging from 2,500 to 7,000 feet. In the fourth quarter of 2000, net daily production averaged 27.9 Mmcf of gas and 856 barrels of oil per day or a total of 33.0 Mcfe per day. After initial flush production, these properties are characterized by gradual decline rates. Gas production is transported through over 4,700 miles of gas gathering systems owned by Great Lakes and is sold primarily to FirstEnergy. Great Lakes sells its gas on a negotiated basis. While Great Lakes may sell gas to third parties, such arrangements must be contracted through FirstEnergy which has the right to match any such arrangements. In September 2000, the parties amended the base contract to have its term automatically renewed for one month periods through June 30, 2001. The amendments identified gas marketing services to be performed by FirstEnergy, and defined fees to be paid by Great Lakes and terms and conditions of the gas purchase agreement were further defined, including pricing, delivery points and projected volumes. At December 31, 2000, Great Lakes had a development inventory of 74 proven recompletions and 1,635 proven drilling locations. Acreage owned by the Appalachian Region at December 31, 2000 included 714,552 gross (335,855 net) developed acres and 348,030 gross (160,004 net) undeveloped acres. During 2000, 142 development wells (63.2 net) were drilled, of which 141 (62.7 net) were productive. Nine exploratory wells (2.6 net) were drilled, of which five (1.6 net) were productive.

Management of Great Lakes is directed by a committee comprised of three representatives from each of the Company and FirstEnergy. Disagreements that cannot be resolved by the committee may be resolved through arbitration.

**Production**

The following table sets forth production information for the preceding five years (in thousands, except average sales price and operating cost data).

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | **1996** | **1997** | **1998** | **1999** | **2000** |
| Production | | | | | |
| Gas (Mmcf) | 21,231 | 38,409 | 45,193 | 50,808 | 41,039 |
| Crude oil (Mbbl) | 1,018 | 1,371 | 2,175 | 2,247 | 2,035 |
| Natural gas liquids (Mbbl) | 50 | 423 | 480 | 412 | 363 |
| Total (Mmcfe) (a) | 27,639 | 49,173 | 61,123 | 66,762 | 55,428 |
| Revenues | | | | | |
| Gas | $47,629 | $101,217 | $105,509 | $108,115 | $118,977 |
| Crude oil | 19,912 | 24,967 | 26,119 | 33,075 | 47,414 |
| Natural gas liquids | 513 | 3,833 | 3,965 | 4,302 | 6,691 |
| Total | 68,054 | 130,017 | 135,593 | 145,492 | 173,082 |
| Direct operating expenses (b) | 20,676 | 31,481 | 39,001 | 43,074 | 38,525 |
| Gross margin | $47,378 | $ 98,536 | $ 96,592 | $102,418 | $134,557 |
| Average sales price(c) | | | | | |
| Gas (Mcf) | $ 2.24 | $ 2.64 | $ 2.33 | $ 2.13 | $ 2.90 |
| Crude oil (Bbl) | 19.56 | 18.21 | 12.01 | 14.72 | 23.30 |
| Natural gas liquids (Bbl) | 10.26 | 9.06 | 8.26 | 10.44 | 18.43 |
| Mcfe (a) | 2.46 | 2.64 | 2.22 | 2.18 | 3.12 |
| Operating cost (Mcfe) | | | | | |
| Direct costs | $ 0.69 | $ 0.57 | $ 0.57 | $ 0.58 | $ 0.59 |
| Severance and production taxes | 0.06 | 0.07 | 0.07 | 0.07 | 0.11 |
| Total | $ 0.75 | $ 0.64 | $ 0.64 | $ 0.65 | $ 0.70 |

(a) Oil and NGL are converted to Mcfe at a rate of 6 Mcf per barrel.
(b) Includes severance and production taxes.
(c) Average sales prices are net of hedging, which reduced average oil and gas prices in 2000 by $4.85 and $0.81, respectively.

### Producing Wells

The following table sets forth information relating to productive wells at December 31, 2000. The Company owns royalty interests in an additional 436 wells. Wells are classified as oil or gas according to their predominant production stream.

| | Wells | | Average Working Interest |
|---|---|---|---|
| | Gross | Net | |
| Crude oil | 1,705 | 1,057 | 62% |
| Natural gas | 8,152 | 3,731 | 46% |
| Total | 9,857 | 4,788 | 49% |

### Acreage

The following table sets forth developed and undeveloped acreage held at December 31, 2000.

| | Acres | | Average Working Interest |
|---|---|---|---|
| | Gross | Net | |
| Developed | 1,133,813 | 567,432 | 50% |
| Undeveloped | 487,688 | 219,457 | 45% |
| Total | 1,621,501 | 786,889 | 49% |

### Drilling Results

The following table summarizes drilling activities for the past three years.

| | Year Ended December 31, | | | | | |
|---|---|---|---|---|---|---|
| | 1998 | | 1999 | | 2000 | |
| | Gross | Net | Gross | Net | Gross | Net |
| Development wells | | | | | | |
| Productive | 222.0 | 182.0 | 43.0 | 20.6 | 173.0 | 82.5 |
| Dry | 12.0 | 8.8 | 3.0 | 1.7 | 6.0 | 4.4 |
| Exploratory wells | | | | | | |
| Productive | 9.0 | 3.9 | 1.0 | 0.5 | 9.0 | 2.9 |
| Dry | 5.0 | 2.9 | 3.0 | 0.8 | 7.0 | 1.7 |
| Total wells | | | | | | |
| Productive | 231.0 | 185.9 | 44.0 | 21.1 | 182.0 | 85.4 |
| Dry | 17.0 | 11.7 | 6.0 | 2.5 | 13.0 | 6.1 |
| Total | 248.0 | 197.6 | 50.0 | 23.6 | 195.0 | 91.5 |

**Real Property**

The Company leases approximately 45,000 square feet of office space in Texas and Oklahoma under standard office lease arrangements that expire at various times through November 2003. All facilities are believed adequate to meet the Company’s current needs and existing space could be expanded or additional space could be leased if required.

In March 2000, a tornado struck the Company’s headquarters in Fort Worth. The Company temporarily relocated to 801 Cherry Street in Fort Worth. In January 2001, the Company entered into a five-year lease for approximately 26,000 square feet of office space located at 777 Main Street in Fort Worth, and plans to move there in April 2001.

The Company owns various vehicles and other equipment that are used in its field operations. Such equipment is believed to be in good repair and, while such equipment is important to its operations, it can be readily replaced as necessary.

**ITEM 3. LEGAL PROCEEDINGS**

The Company is involved in various legal actions and claims arising in the ordinary course of business. In the opinion of management, such litigation and claims are likely to be resolved without material adverse effect on the Company’s financial position or results of operations.

In May 1998, a Domain stockholder filed an action in the Delaware Court of Chancery, alleging that the terms of the merger of Domain into Range were unfair to a purported class of Domain stockholders and that the defendants (except Range) had violated their legal duties in connection with the merger. Range is alleged to have aided and abetted the breaches of fiduciary duty allegedly committed by the other defendants. The action sought to enjoin the merger as well as claiming money damages. In September 1998, the parties executed a Memorandum of Understanding (“MOU”), which represented a settlement in principle. Under the terms of the MOU, appraisal rights (subject to certain conditions) were offered to all holders of Domain common stock (excluding the defendants and their affiliates) and Domain agreed to pay court-awarded fees and expenses of plaintiffs’ counsel in an amount not to exceed $300,000. The settlement remains subject to court approval and certain other conditions which appear unlikely to be met.

In February 2000, a royalty owner filed a suit asking for a class action certification against Great Lakes Energy Partners L.L.C. and the Company in the New York Supreme Court, alleging that gas was sold to affiliates and gas marketers at low prices, inappropriate post production expenses reduced proceeds to the royalty owners, and that Great Lakes improperly accounted for the royalty owners’ share of gas. The action sought a proper accounting for all gas sold, an amount equal to the difference in prices paid and the highest obtainable prices, punitive damages and attorneys’ fees. The case has been remanded to state court in New York. While the outcome of this suit is uncertain, the Company believes it will be resolved without material adverse effect on its financial position or result of operations.

**ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS**

None.

## PART II

## ITEM 5. MARKET FOR THE COMMON STOCK AND RELATED MATTERS

The Company's common stock is listed on New York Stock Exchange ("NYSE") under the symbol "RRC." Prior to August 1998, the stock was listed under the symbol "LOM." During 2000, trading volume averaged 329,317 shares per day. On March 1, 2001, the closing price of the common stock was $5.91. The following table sets forth the high and low sales prices as reported on the NYSE composite tape over the past two years.

| | High | Low | Average Daily Volume |
|---|---|---|---|
| **1999** | | | |
| First quarter | $3.81 | $1.56 | 251,690 |
| Second quarter | 7.13 | 2.38 | 239,062 |
| Third quarter | 6.94 | 3.94 | 136,213 |
| Fourth quarter | 4.69 | 2.44 | 173,575 |
| **2000** | | | |
| First quarter | $3.44 | $1.88 | 230,470 |
| Second quarter | 3.31 | 1.44 | 382,015 |
| Third quarter | 5.31 | 2.88 | 366,314 |
| Fourth quarter | 7.00 | 4.00 | 339,306 |

From December 31, 2000 through March 1, 2001 the common stock has traded at prices between $5.50 and $7.13 per share. The Company's $2.03 convertible preferred stock, 5.75% trust preferred, 6% convertible debentures and 8.75% senior subordinated notes are not listed on an exchange but trade over the counter.

### Holders of Record

At March 1, 2001 there were approximately 2,494 holders of record of the common stock.

### Dividends

Common stock dividends were initiated in 1995 and paid quarterly through the third quarter of 1999. In the first quarter of 1999, the dividend was reduced and in the fourth quarter of 1999 it was eliminated in connection with continuing losses. The convertible preferred stock is entitled to receive cumulative quarterly dividends at an annual rate of $2.03 per share.

In September 2000, the Company authorized a $2.03 Convertible Exchangeable Preferred Stock Series D, having terms substantially identical to the outstanding Series C Preferred, with the exception that dividends could be paid in common stock. In November 2000, 523,140 shares of Series C were exchanged for Series D on a one-for-one basis. In December 2000, 323,140 shares of Series D were exchanged for common stock. The Company elected to pay fourth quarter 2000 Series D dividends in common stock. Subsequent to December 31, 2000, all remaining shares of Series D and all but 8,235 shares of Series C were exchanged for common stock. Annual cash dividend requirements on the remaining Series C Preferred amount to less than $17,000.

The payment of dividends is subject to declaration by the Board of Directors and depends on earnings, capital expenditures and various other factors. The bank credit facility and the 8.75% senior subordinated notes contain restrictions on the ability to pay dividends. The bank credit facility currently prohibits common stock dividends. Under the terms of the 8.75% senior subordinated notes, the Company may pay restrictive payments, including dividends, equal the greater of: i) $20 million or ii) a formula which includes earnings and losses since the issuance of the notes. Given the Company's losses since 1997, the Company cannot make payments under the formula and must rely on the $20 million basket. At December 31, 2000, $4.9 million remained available under the basket.

## ITEM 6. SELECTED FINANCIAL DATA

The following table presents selected financial information covering the last five years.

| | As of or for the Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 1996 | 1997 | 1998 | 1999 | 2000 |
| | (In thousands, except per share data) | | | | |
| **Operations** | | | | | |
| Revenues | $ 75,341 | $145,417 | $ 148,929 | $201,364 | $187,719 |
| Net income (loss) | 12,615 | (23,332) | (175,150) | (7,793) | 37,961 |
| Earnings (loss) per share before extraordinary items – basic | 0.71 | (1.31) | (6.82) | (0.34) | 0.57 |
| Earnings (loss) per share before extraordinary items – diluted | 0.69 | (1.31) | (6.82) | (0.34) | 0.57 |
| Earnings (loss) per share – basic | 0.71 | (1.31) | (6.82) | (0.27) | 0.99 |
| Earnings (loss) per share – diluted | 0.69 | (1.31) | (6.82) | (0.27) | 0.99 |
| Dividends per common share | 0.06 | 0.10 | 0.12 | 0.03 | — |
| **Balance Sheet** | | | | | |
| Working capital | $ 12,896 | $ (2,051) | $ (9,484) | $ 22,225 | $ 16,227 |
| Oil and gas properties, net | 229,417 | 623,807 | 662,099 | 592,363 | 571,842 |
| Total assets | 282,547 | 758,833 | 921,612 | 752,368 | 689,165 |
| Senior debt | 61,780 | 186,712 | 367,062 | 140,000 | 89,900 |
| Non-recourse debt | — | — | 60,100 | 142,520 | 113,009 |
| Subordinated debt | 55,000 | 180,000 | 180,000 | 176,360 | 162,550 |
| Trust Preferred | — | 120,000 | 120,000 | 117,669 | 92,640 |
| Stockholders' equity | 117,529 | 196,950 | 133,222 | 127,171 | 185,207 |

The following table sets forth summary unaudited financial information on a quarterly basis for the past two years (in thousands, except per share data).

| | 1999 | | | |
|---|---|---|---|---|
| | March 31 | June 30 | Sept. 30 | Dec. 31 |
| Revenues (a) | $ 37,953 | $ 42,196 | $ 81,095 | $ 40,121 |
| Net income (loss) (a)(b) | (8,981) | (2,087) | 12,722 | (9,446) |
| Earnings (loss) per share —basic and diluted (a)(b) | (0.26) | (0.07) | 0.33 | (0.27) |
| Total assets (b) | 905,522 | 895,677 | 775,785 | 752,368 |
| Senior debt | 317,451 | 317,085 | 146,650 | 140,000 |
| Non-recourse debt | 60,100 | 54,200 | 146,755 | 142,520 |
| Subordinated notes | 180,000 | 176,360 | 176,360 | 176,360 |
| Trust Preferred | 120,000 | 117,669 | 117,669 | 117,669 |
| Stockholders' equity (a)(b) | 124,886 | 125,970 | 137,090 | 127,171 |

| | 2000 | | | |
|---|---|---|---|---|
| | March 31 | June 30 | Sept. 30 | Dec. 31 |
| Revenues | $ 42,839 | $ 41,336 | $ 44,819 | $ 58,725 |
| Net income (c) | 4,281 | 8,735 | 7,756 | 17,189 |
| Earnings per share —basic and diluted (c) | 0.12 | 0.23 | 0.19 | 0.42 |
| Total assets | 727,214 | 700,439 | 687,500 | 689,165 |
| Senior debt | 142,000 | 112,000 | 99,900 | 89,900 |
| Non-recourse debt | 130,619 | 124,516 | 120,012 | 113,009 |
| Subordinated debt | 176,060 | 174,810 | 165,660 | 162,550 |
| Trust Preferred | 111,490 | 100,240 | 97,340 | 92,640 |
| Stockholders' equity (c) | 134,164 | 147,900 | 162,371 | 185,207 |

(a) Includes a gain recorded in the third quarter associated with the Great Lakes Energy Partners transaction. See Note 18 to the financial statements.

(b) Includes a $2.4 million extraordinary gain on retirement of securities recorded in the second quarter, a $21.0 million provision for impairment on the Sterling Plant recorded in the third quarter and a $6.1 million provision for impairment of oil and gas properties recorded in the fourth quarter.

(c) Includes extraordinary gains on retirement of securities of $3.5 million, $7.0 million, $4.3 million and $3.0 million recorded for each of the four quarters of 2000, respectively.

The total of the earnings per share for each quarter does not equal the earnings per share for the full year, either because the calculations are based on the weighted average shares outstanding during each of the individual periods or rounding.

## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (Capitalized terms herein are defined in the footnotes to the Consolidated Financial Statements contained herein.)

### Factors Affecting Financial Condition and Liquidity

### Liquidity and Capital Resources

During 2000, the Company spent $58.2 million on development, exploration and acquisitions. Debt (including Trust Preferred) decreased by $118.5 million to $458.1 million. Debt (including Trust Preferred) and $2.03 Preferred decreased by $141.7 million, including $23.2 million face value of $2.03 Preferred retired at a discount. At December 31, 2000, the Company had $2.5 million in cash, total assets of $689.2 million and a debt (including Trust Preferred) to capitalization ratio of 71.2%. The unused borrowing base available at December 31, 2000 was $25.1 million on the Credit Facility, $31.0 million on the Great Lakes Facility and $18.5 million on the IPF Facility.

Long-term debt (including Trust Preferred) at December 31, 2000 totaled $458.1 million and included $89.9 million of borrowings under the Credit Facility, $84.5 million under the non-recourse Great Lakes Facility, $28.5 million under the non-recourse IPF Facility, $125.0 million of 8.75% Senior Subordinated Notes, $37.6 million of 6% Convertible Subordinated Debentures and $92.6 million of Trust Preferred.

During 2000, 5.7 million shares of common stock were exchanged for $25.0 million of Trust Preferred and $13.8 million of 6% Debentures. A $17.8 million extraordinary gain net of costs was recorded as the Trust Preferred and 6% Debentures were acquired at a discount. In addition, 4.6 million shares of common stock were exchanged for $23.2 million of the $2.03 Preferred.

In September 1999, the Company decided to sell the Sterling Plant and reduced its carrying value to estimated fair value through an impairment of $21.0 million. The sale of the plant in June 2000 resulted in an additional $716,000 loss.

The Company currently believes its capital resources are adequate to meet its requirements for at least the next twelve months. However, future cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and gas business. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain planned capital expenditures.

*Cash Flow*

The Company’s principal sources of cash are operating cash flow and bank borrowings. The Company’s cash flow is highly dependent on oil and gas prices. Decreases in prices and lower production at certain properties reduced cash flow sharply in 1998 and early 1999 and resulted in the reduction of the Company’s borrowing base. The Company has entered into hedging agreements covering approximately 64% and 7% of its anticipated production on an Mcfe basis for 2001 and 2002, respectively. Simultaneously, the Company sharply reduced its development and exploration spending. While the $58.2 million of capital expenditures for 2000 were funded entirely with internal cash flow, the amount expended was not sufficient to replace production.

Net cash provided by operations in 1998, 1999 and 2000 was $45.0 million, $50.2 million and $74.1 million, respectively. Cash flow from operations increased as higher prices, a decrease in direct operating costs and lower interest expense more than offset the decline in production and increasing general and administrative expenses.

Net cash used in (provided by) investing in 1998, 1999 and 2000 was $172.3 million, $(98.2) million and $5.3 million, respectively. In 1999, a $98.7 million source of cash from the formation of Great Lakes, $17.5 million in asset sales and $13.2 million of IPF receipts, more than offset additions to oil and gas properties and IPF investments. In 2000, $46.8 million of additions to oil and gas properties, offset by $25.9 million proceeds from sales of assets and $24.8 million of IPF repayments were included.

Net cash provided by (used in) financing in 1998, 1999 and 2000 was $128.5 million, $(146.4) million and $(79.3) million, respectively. Sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings. During 2000, recourse debt decreased by $63.9 million and total debt (including Trust Preferred) decreased by $118.5 million. The reduction in debt was the result of applying excess cash flow and proceeds from the sale of assets to debt repayment and exchanges of common stock for fixed income securities. The amount of Trust Preferred outstanding decreased $2.3 million in 1999 and $25.0 million in 2000 due to exchanges of such securities into common stock.

*Capital Requirements*

During 2000, $58.2 million of capital was expended, primarily on development projects. This represented approximately 61% of internal cash flow. The Company manages its capital budget with the goal of funding it with internal cash flow. Development and exploration activities are highly discretionary, and, for the foreseeable future, management expects such activities to be maintained at levels below internal cash flow. Remaining cash flow should be available for debt reduction. See “Business—Development and Exploration Activities.”

*Bank Facilities*

The Credit Facility is secured by oil and gas properties. At March 1, 2001, the borrowing base on the Credit Facility was $115 million of which $21.1 million was available. The borrowing base is subject to redetermination each April and October, as well as under special circumstances. The borrowing base is dependent on a number of factors, including the lenders’ discounted present value of estimated future net cash flow from production. Borrowing base redeterminations resulting in no change or a decrease require approval of 75% of the lenders, redeterminations which result in an increase require 100% approval.

The Company expects to further reduce bank borrowings in the coming year with internal cash flow and, possibly, asset sales. During 2000, the Company sold properties and used $25.9 million of proceeds to reduce bank borrowings. There are currently no agreements to sell any material assets.

The Company consolidates 50% of amounts outstanding under Great Lakes’s $275 million revolving bank facility. The Great Lakes Facility is non-recourse to Range. The Great Lakes Facility provides for a borrowing base which is subject to semi-annual redetermination and is secured by substantially all of the joint venture’s assets. At March 1, 2001, Great Lakes’ borrowing base was $200 million, of which $40 million was available. The borrowing base is subject to semi-annual redeterminations in April and October. Borrowing base redeterminations require the approval of all lenders.

IPF maintains a $100 million revolving credit facility. The IPF Facility is secured by substantially all of IPF’s assets and is non-recourse to Range. IPF’s borrowing base is subject to semi-annual redetermination in April and October. On March 1, 2001, the IPF borrowing base was $37 million, of which $13.6 million was available.

*Oil and Gas Hedging*

The Company regularly enters into hedging agreements to reduce the impact of fluctuations in oil and gas prices. All such contracts are entered into solely to hedge price and to limit volatility. The Company’s current policy is to hedge between 50% and 75% of its production on a rolling twelve to eighteen month basis. At December 31, 2000, hedges were in place covering 33.7 Bcf of gas and 1.0 million barrels of oil at prices ranging from $2.84 to $6.78 per Mmbtu (averaging $4.07) and from $26.96 to $33.71 per barrel (averaging $28.62). While these transactions have no carrying value, their fair value, represented by the estimated amount that would be required to terminate them, was a net loss of $72.1 million and $54.5 million at December 31, 2000, and February 28, 2001, respectively. The contracts expire monthly through December 2002 and cover approximately 64% of anticipated 2001 production and 7% of 2002 production. Gains or losses on hedging transactions are determined as the difference between the contract price and a reference price, generally closing prices on the NYMEX. Transaction gains and losses are determined monthly and are included in oil and gas revenues in the period the hedged production is sold. Net gains (losses) relating to these derivatives in 1998, 1999 and 2000 approximated $3.1 million, $(10.6) million and $(43.2) million, respectively. Effective January 1, 2001, the gains (losses) in these hedging positions will be recorded at fair value on the Company’s Balance Sheet as Other Comprehensive Income (Loss), a component of Stockholders’ Equity.

In June 2000, the Company repriced 4.1 Bcf of existing gas hedges upwards from an average price of $2.59 to $3.00 per Mmbtu to conserve cash. In exchange for such repricing, the Company hedged an average of 22,700 Mmbtu per day from April 2001 through March 2002 at an average price of $3.20 per Mmbtu. While the Company’s payment requirement relating to the repriced hedges was affected, under generally accepted accounting principles the $6.0 million of estimated net losses deferred were recorded as if no repricing had occurred. A deferred loss and associated liability of $6.9 million were recorded on the Balance Sheet at June 30, 2000, of which $665,000 and $945,000 remained at December 31, 2000, respectively. The imputed interest cost associated with the repricing was $168,000.

*Interest Rate Hedging*

At December 31, 2000, Range had $458.1 million of debt (including Trust Preferred) outstanding. Of this amount, $162.6 million bears interest at fixed rates averaging 8.1%. Senior debt and Non-recourse debt totaling $202.9 million bears interest at floating rates which averaged 8.7% at year-end 2000. At December 31, 2000, the Company had $20.0 million of borrowings subject to an interest rate swap agreement based on 30-day LIBOR of 5.59% expiring in October 2001. The agreement requires the Company to pay the counterparty interest at the above fixed swap rate and requires the counterparty to pay the Company interest at the 30-day LIBOR rate. In addition, Great Lakes had four interest rate swap agreements totaling $65 million. Two agreements totaling $45 million at rates of 7.09% each expire in May 2004. Two agreements of $10 million each at 6.20% and 6.22% expire in December 2002. The agreements expiring in May 2004 and December 2002 may be terminated at the counterparty's option in May 2002 and December 2001, respectively. The 30-day LIBOR rate on December 31, 2000 was 6.5%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2000 would cost the Company approximately $2.0 million in additional annual interest.

*Capital Restructuring Program*

As more fully described in Note 1 to the Consolidated Financial Statements, the Company took a number of steps beginning in 1998 to strengthen its financial position, including the sale of assets and the exchange of common stock for fixed rate securities. These initiatives resulted in reducing parent company bank debt to $89.9 million and total debt (including Trust Preferred) to $458.1 million at December 31, 2000. While management believes these steps have stabilized the Company's financial position, debt remains too high. For the Company to return to its historical posture of consistent profitability and growth, management believes it necessary to further reduce debt. The Company currently believes it has sufficient liquidity and cash flow to meet its obligations for the next twelve months; however, a drop in oil and gas prices or a reduction in production or reserves would reduce the Company's ability to fund capital expenditures and meet its obligations.

**Inflation and Changes in Prices**

The Company's revenues and the value of its assets have been and will continue to be affected by changes in oil and gas prices. The Company's ability to maintain current borrowing capacity and to obtain additional capital on attractive terms is also dependent on oil and gas prices. Oil and gas prices are subject to significant fluctuations that are beyond the Company's ability to control or predict. During 2000, the Company received an average of $23.30 per barrel of oil and $2.90 per Mcf of gas after hedging. Although certain of the Company's costs and expenses are affected by the general inflation, inflation does not normally have a significant effect on the Company. Should conditions in the oil industry remain favorable, inflationary pressures specific to the industry have and may continue to accelerate.

## Results of Operations

The following table identifies certain unusual items included in net income, and presents net income excluding the effect of such items. The table should be read in conjunction with the following discussions of results of operations.

| | Year Ended December 31, | | | |
|---|---|---|---|---|
| | 1997 | 1998 | 1999 | 2000 |
| | (in thousands) | | | |
| Net income (loss) as reported | $(23,332) | $(175,150) | $ (7,793) | $ 37,961 |
| Impact of hedging, net | 900 | (3,100) | 10,632 | 43,177 |
| Unusual items: | | | | |
| Provisions for impairment, net of tax | 38,742 | 157,417 | 27,118 | — |
| Restructuring costs | — | 3,147 | — | — |
| Gain (loss) from asset sales | (8,154) | (1,817) | 530 | 1,116 |
| Gain on sale —Great Lakes, net of tax | — | — | (38,310) | — |
| Gain on retirement of debt | — | — | (2,430) | (17,763) |
| Reversal of tax provision | — | — | — | (1,101) |
| Reversal of IPF valuation allowances | — | — | — | (1,299) |
| | 30,588 | 158,747 | (13,092) | (19,047) |
| As adjusted | $ 8,156 | $ (19,503) | $(10,253) | $ 62,091 |

Based on oil and gas hedging contracts in place at December 31, 2000, an additional $72.1 million of comprehensive loss would be recognized at December 31, 2000 had SFAS No. 133 been in effect on that date.

*Comparison of 2000 to 1999*

Net income in 2000 totaled $38.0 million, compared to a net loss of $7.8 million in 1999. Net income excluding the impact of hedging losses and unusual items would have been $62.1 million in 2000 versus a net loss of $10.3 million in 1999. Production fell to 151,442 Mcfe per day, a 17% decrease from 1999. A 4% decrease would have been reported if the impact of the effect of the Great Lakes transaction were eliminated. Revenues benefited from a 43% increase in average prices per Mcfe to $3.12, partially offset by the production decrease. The average prices received for oil increased 58% to $23.30 per barrel and for gas increased 36% to $2.90 per Mcf. Production expenses fell 11% to $38.5 million largely as a result of the Great Lakes transaction and asset divestitures. The operating cost per Mcfe produced averaged $0.65 in 1999 versus $0.70 in 2000 due to production taxes and workovers.

Transportation, processing and marketing revenues decreased 32% to $5.3 million. The benefit to processing revenues of higher NGL prices was more than offset by the impact of the Sterling gas plant sale in April 2000. IPF’s $10.0 million of revenues consisted of the return portion of its royalties and a $1.3 million net reversal of valuation allowances previously provided. IPF’s income rose 27% over that reported in 1999. During 2000, IPF expenses included $1.5 million of administrative costs and $3.4 million of interest.

Exploration expense increased 32% to $3.2 million, primarily due to higher dry hole costs.

General and administrative expenses increased 29% to $10.3 million. The increase was primarily due to lower recoupments from third parties for operations which fell due to the Great Lakes transaction and the expense of establishing duplicate financial and administrative departments in Fort Worth.

Interest and other income decreased $1.1 million primarily due to $1.1 million of losses on sales of assets. Interest expense (excluding IPF) decreased 15% to $40.0 million primarily as a result of the lower outstandings, partially offset by higher interest rates. See the discussion of IPF interest expense in Note 6. The average outstanding balance on the bank credit facility fell to $125 million from $308 million in the prior year as the weighted average interest rate rose to 8.8% from 7.1%.

Depletion, depreciation and amortization (“DD&A”) decreased 6% as a result of the mix of production and lower production. The Company-wide depletion rate rose to $1.30 per Mcfe compared to $1.04 in 1999 as determined based on ending reserves and the costs associated with them. Unproved properties are assessed periodically to determine whether there has been an impairment. If an impairment is indicated, a loss is recognized. The Company compares the carrying value of its unproved properties to their estimated fair value based on a variety of factors, including a geological and engineering assessment of the area and other acreage transactions in the vicinity. In the fourth quarter of 2000, the Company raised its DD&A rate to $1.38 per Mcfe to reflect a decline in future proved reserves and the cost of properties subject to amortization. Reserves were revised downward in 2000 due to the removal of drilling and recompletion locations that, based on perceived risk, will probably not be drilled. See Note 20 to the financial statements. The Company currently estimates that its DD&A rate for 2001 will approximate $1.34 per Mcfe. The Company’s high DD&A rate will make it more difficult to remain profitable if commodity prices fall sharply.

*Comparison of 1999 to 1998*

The Company reported a net loss for 1999 of $7.8 million, compared to a net loss of $175.2 million in 1998. Net losses excluding the impact of hedging and unusual items would have been $10.3 million in 1999 compared to $19.5 million in 1998.

Oil and gas revenues increased 7% to $145.5 million. During the year, production increased 9% to 66.8 Bcfe, an average of 182,900 Mcfe per day. The increased revenues recognized from production were partially offset by a 2% decline in the average price received of $2.18 per Mcfe. The average oil price increased 23% to $14.72 per barrel while the average gas price decreased 9% to $2.13 per Mcf. In 1999, the Company sold 2.8 Bcf of gas under an above-market contract to a utility at an average price of $3.81 per Mcf. Had this gas been sold at the average price in the region (approximately $2.32 per Mcf), gas revenues would have been $3.9 million lower. The gas contract expired in mid-2000. As a result of the Company’s larger base of producing properties, production expenses increased 10% to $43.1 million in 1999. The average operating cost per Mcfe produced was $0.64 in 1998 and $0.65 in 1999.

Transportation, processing and marketing revenues increased 16% to $7.8 million due to higher production levels. IPF income of $7.8 million consisted of the return portion of its royalties net of a $3.3 million allowance for bad debts. During 1999, IPF income expenses included $1.5 million of administrative expenses and $4.3 million of interest.

Exploration expense decreased 78.8% to $2.4 million in 1999. During 1999, the Company sharply reduced exploration expenditures to help reduce indebtedness and limit risk.

General and administrative expenses decreased 13% from $9.2 million in 1998 to $8.0 million in 1999. As a percentage of revenues, general and administrative expenses were 4.0% in 1999 as compared to 6.2% in 1998. The decrease was due to an overhead reduction program implemented in late 1998 and the benefits of sharing certain services with Great Lakes.

Interest and other income decreased $1.8 million to $420,000 primarily due to $1.3 million of losses on asset sales. The $39.8 million gain on sale in 1999 represented the proportional gain recognized on the

Great Lakes transaction as described in Note 18. Interest expense increased 16% to $47.1 million primarily a result of the higher outstandings and higher interest rates. Average outstandings on the Credit Facility were $272 million and $308 million for 1998 and 1999, respectively and the weighted average interest rates were 6.7% and 7.1%.

Depletion, depreciation and amortization increased 27% from the prior year due to higher production and lower proved reserves. The Company-wide depletion increased from $.89 per Mcfe in 1998 to $1.04 per Mcfe in 1999. In the third quarter of 1999, the Company recognized a $21 million impairment on a gas processing plant located in the Permian Basin upon deciding to sell the plant and related assets. The net book value of the plant was classified as a current asset at December 31, 1999 on the Balance Sheet (See Note 5 - Dispositions). During 1999, the Company recorded $3.1 million of depreciation expense for the first nine months on this plant. In the fourth quarter of 1999, the Company recognized an impairment of $6.1 million on unproved acreage value. Unproved properties are assessed periodically to determine whether an impairment is indicated. If it is, a loss is recognized. The Company compares the carrying value of its unproved properties to its estimate of their fair value. The assessment of fair value is based on various factors including a geological and engineering assessment of the area and acreage transactions in the vicinity. In the fourth quarter of 1999, the Company again adjusted its DD&A rate upward to $1.33 per Mcfe to reflect decreasing reserves. Reserves were revised downward based on in-depth field studies which showed sharper declines in production and reservoir pressures than previously expected.

*Comparison of 1998 to 1997*

The Company reported a net loss of $175.2 million in 1998, as compared to a net loss of $23.3 million in 1997. Excluding the impact of hedging and unusual items, net loss for 1998 would have been $19.5 million and net income for 1997 would be $8.2 million. Due to downward engineering revisions on certain of its properties and, to a lesser degree, depressed energy prices, the Company recorded an impairment of $207.1 million ($156.2 million after tax) as well as $5.9 million ($5.0 million after tax) of valuation allowances on IPF receivables. The Company initiated a restructuring plan to reduce costs and improve operating efficiencies. In connection with the cost reduction program, the Company recorded a charge of $3.1 million ($2.7 million after tax) relating to severance and other matters.

Oil and gas revenues increased 4% to $135.6 million. Production increased 24% to 61.1 Bcfe, an average of 167.5 Mmcfe per day. The increased production revenues were partially offset by a 16% decrease in the average price received per Mcfe to $2.22. The average oil price decreased 34% to $12.01 per barrel and average gas prices decreased 12% to $2.33 per Mcf. During 1998, the Company sold 4.0 Bcf of gas to a utility under an above market gas contract at an average price of $3.77 per Mcf. Had this gas been sold at the average price available in the region ($3.16 per Mcf), gas revenues would have decreased $2.4 million. As a result of a larger base of producing properties, production expenses increased 24% to $39.0 million in 1998 versus $31.5 million in 1997. The average operating cost per Mcfe produced was $0.64 in both periods.

Transportation, processing and marketing revenues decreased 14% to $6.7 million principally due to the sale of a gas processing plant in the San Juan Basin and a drop in NGL prices which lowered processing revenues. IPF income of $4.4 million was recorded for the four months it was owned. Its expenses during this period included $.5 million of administrative costs, $1.6 million of interest and a $5.9 million of valuation allowances for bad debts.

Exploration expense increased 346% to $11.3 million due to higher seismic and dry hole costs. In 1998, $4.3 million was spent on dry holes compared to only $300,000 of such costs in 1997.

General and administrative expenses increased 74% to $9.2 million. As a percentage of revenues, general and administrative expenses were 6.2% in 1998, compared to 4% in 1997. The increase was due to higher personnel costs and increased legal expenses. In December 1998, the Company implemented an overhead reduction program in response to its poor performance and falling energy prices. The cuts included the termination of 54 employees, representing 27% of non-field staff.

Interest and other income decreased 70% to $2.3 million primarily due to lower profits on assets sales. Interest expense increased 50% to $40.6 million primarily as a result of the higher outstandings due to acquisitions and drilling. Average outstandings on the Credit Facility were $192.1 million and $271.6 million for 1997 and 1998, respectively, and the weighted average interest rates were 7.3% and 6.7%.

Depletion, depreciation and amortization increased 9% compared to 1997 as a result of increased production. The increase was partially offset by a decrease in the average depletion rate per Mcfe. The Company-wide depletion rate was $1.03 per Mcfe in 1997 and $.89 per Mcfe in 1998. In 1998, the Company recorded $5.5 million of depletion expense on properties classified as assets held for sale at year end.

In 1998, the Company recorded a sizeable impairment against its oil and gas properties as a result of poor performance and, to a lesser extent, lower oil and gas prices. The following properties were impaired during 1998 (in thousands):

| Properties | Impairment |
|---|---|
| Southwest | $ 88,325 |
| Gulf Coast – offshore | 55,460 |
| Gulf Coast – onshore | 38,362 |
| Appalachia | 14,644 |
| Marketable securities | 10,337 |
| Total | $207,128 |

**Year 2000**

Range experienced no material problems relating to the Year 2000 issues. The Company’s significant suppliers, customers and service providers have been able to transact business on a normal basis in 2000. The total cost for the Year 2000 projects approximated $200,000.

**ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about Range’s potential exposure to market risks. The term “market risk” refers to the risk of loss arising from adverse changes in oil and gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how Range views and manages its ongoing market risk exposures. All of Range’s market risk sensitive instruments were entered into for purposes other than trading.

*Commodity Price Risk.* Range’s major market risk exposure is in the pricing applicable to its oil and gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices applicable to U.S. natural gas production. Pricing for oil and gas production has been volatile and unpredictable for several years.

Range periodically enters into financial hedging activities with respect to a portion of its projected oil and natural gas production through financial swaps whereby Range will receive a fixed price for its production and pay a variable market price to the contract counterparty. These financial hedging activities are intended to reduce the impact of oil and gas price fluctuations. Realized gains and losses from the settlement of these hedges are recognized in oil and gas revenues when the associated production occurs. The gains and losses realized as a result of hedging are substantially offset in the cash market when the commodity is delivered. Range does not hold or issue derivative instruments for trading purposes.

As of December 31, 2000, Range had oil and gas hedges in place covering 33.7 Bcf of gas and 1.0 million barrels of oil. While these transactions have no carrying value, their fair value, represented by the estimated amount that would be required to terminate them, was a net loss of $72.1 million at December 31, 2000. Due to the decline in commodity prices, particularly natural gas, subsequent to year end, the fair market value of these hedge transactions was a net loss of $54.5 million at February 28, 2001. The contracts expire monthly through December 2002 and cover approximately 64% of anticipated 2001 production and 7% of 2002 production. Gains or losses on hedging transactions are determined as the difference between the contract price and a reference price, generally closing prices on the NYMEX. Transaction gains and losses are determined monthly and are included in oil and gas revenues in the period the hedged production is sold. Net gains (losses) relating to these derivatives in 1998, 1999 and 2000 approximated $3.1 million, $(10.6) million and $(43.2) million, respectively. Effective January 1, 2001, the gains (losses) in these hedging positions will be recorded at fair value on the Company's balance sheet as Other Comprehensive Income (Loss), a component of Stockholders' Equity.

The Company seeks to reduce the volatility of its oil and gas revenue through hedging transactions. Should the price of a commodity decline, the revenue received from the sale of the product tends to decline to a corresponding extent. The decline in revenue is then partially offset based on the amount of production hedged and the hedge price. In 2000, a 10% reduction in oil and gas prices would have reduced revenue by $21.6 million, offset by a reduction in hedging losses of $15.6 million. If oil and gas future prices at December 31, 2000 had declined by 10%, the hedging loss exposure at that date would have been reduced by $29.4 million.

At December 31, 2000, Range had $458.1 million of debt (including Trust Preferred) outstanding. Of this amount, $162.6 million bears interest at fixed rates averaging 8.1%. The remaining $202.9 million of debt bears interest at floating rates which averaged 8.7% for the year then ended. At December 31, 2000, the Company had $20 million of borrowings subject to an interest rate swap agreement at 5.59% which expires in October 2001. The agreement requires that the Company pay the counterparty interest at the above rate and requires the counterparty to pay the Company interest at the 30-day LIBOR rate. In addition, Great Lakes had four interest rate swap agreements totaling $65 million. Two agreements totaling $45 million at rates of 7.09% each expire in May 2004. Two agreements of $10 million each at 6.20% and 6.22% expire in December 2002. The agreements expiring in May 2004 and December 2002 may be terminated at the counterparty's option in May 2002 and December 2001, respectively. On December 31, 2000, the 30-day LIBOR rate was 6.5%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2000 would cost the Company approximately $2.0 million in additional annual interest.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Reference is made to the Index to Financial Statements on page 40 for a list of financial statements and notes thereto and supplementary schedules. Schedules I, III, IV, V, VI, VII, VIII, IX, X, XI, XII and XIII have been omitted as not required or not applicable, or because the information required to be presented is included in the financial statements and related notes.

### Management Responsibility for Financial Statements

The financial statements have been prepared by management in conformity with generally accepted accounting principles. Management is responsible for the fairness and reliability of the financial statements and other financial data included in this report. In the preparation of the financial statements, it is necessary to make informed estimates and judgments based on currently available information on the effects of certain events and transactions.

The Company maintains accounting and other controls which management believes provide reasonable assurance that financial records are reliable, assets are safeguarded and transactions are properly recorded. However, limitations exist in any system of internal control based upon the recognition that the cost of the system should not exceed benefits derived.

The Company's independent auditors, Arthur Andersen LLP, are engaged to audit the financial statements and to express an opinion thereon. Their audit is conducted in accordance with generally accepted auditing standards to enable them to report whether the financial statements present fairly, in all material respects, the financial position and results of operations in accordance with generally accepted accounting principles.

## ITEM 9. CHANGE IN ACCOUNTANTS AND DISAGREEMENTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

# PART III

## ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE COMPANY

The officers and directors are listed below with a description of their experience and certain other information. Each director was elected for a one-year term at the Company's 2000 annual stockholders' meeting of stockholders. Officers are appointed by the Board of Directors.

| | Age | Office Held Since | Position |
|---|---|---|---|
| Thomas J. Edelman | 50 | 1988 | Chairman and Chairman of the Board |
| John H. Pinkerton | 46 | 1990 | CEO, President and Director |
| Robert E. Aikman | 69 | 1990 | Director |
| Anthony V. Dub | 51 | 1995 | Director |
| Allen Finkelson | 54 | 1994 | Director |
| Alexander P. Lynch | 48 | 2000 | Director |
| James E. McCormick | 73 | 2000 | Director |
| Terry W. Carter | 48 | 2001 | Executive Vice President – Exploration and Production |
| Eddie M. LeBlanc III | 52 | 2000 | Senior Vice President and Chief Financial Officer |
| Herbert A. Newhouse | 56 | 1998 | Senior Vice President – Gulf Coast |
| Chad L. Stephens | 45 | 1990 | Senior Vice President – Southwest |
| Rodney L. Waller | 51 | 1999 | Senior Vice President and Corporate Secretary |

*Thomas J. Edelman,* Chairman and Chairman of the Board of Directors, joined the Company in 1988. From 1981 to 1997, Mr. Edelman served as a director and President of Snyder Oil Corporation ("SOCO"), a publicly traded independent oil and gas company. In 1996, Mr. Edelman was appointed Chairman and Chief Executive Officer of Patina Oil & Gas Corporation. Prior to 1981, Mr. Edelman was a Vice President of The First Boston Corporation. From 1975 through 1980, Mr. Edelman was with Lehman Brothers Kuhn Loeb Incorporated. Mr. Edelman received his Bachelor of Arts Degree from Princeton University and his Masters Degree in Finance from Harvard University's Graduate School of Business Administration. Mr. Edelman serves as a director of Star Gas Partners, L.P., a publicly-traded master limited partnership, which distributes fuel oil and propane and of Wellogix, Inc., a private company seeking to provide e-commerce solutions to the oil industry.

*John H. Pinkerton,* CEO, President and a Director, became a director in 1988. He joined the Company and was appointed President in 1990. Previously, Mr. Pinkerton was Senior Vice President-Acquisitions of SOCO. Prior to joining SOCO in 1980, Mr. Pinkerton was with Arthur Andersen &

Co. Mr. Pinkerton received his Bachelor of Arts Degree in Business Administration from Texas Christian University and his Master of Arts Degree in Business Administration from the University of Texas. Mr. Pinkerton is also a director of Venus Exploration, Inc., a publicly traded exploration and production company in which Range owned approximately a 18% interest at December 31, 2000.

*Robert E. Aikman,* became a Director in 1990. Mr. Aikman has more than 40 years experience in petroleum and natural gas exploration and production throughout the United States and Canada. From 1984 to 1994 he was Chairman of the Board of Energy Resources Corporation. From 1979 through 1984, he was the President and principal shareholder of Aikman Petroleum, Inc. From 1971 to 1977, he was President of Dorchester Exploration Inc. and from 1971 to 1980, he was a Director and a member of the Executive Committee of Dorchester Gas Corporation. Mr. Aikman is also Chairman of Provident Communications, Inc., Vice-Chairman of Whamtech, Inc., and President of The Hawthorne Company, an entity which organizes joint ventures and provides advisory services for the acquisition of oil and gas properties, including the financial restructuring, reorganization and sale of companies. In addition, Mr. Aikman is a director of the Panhandle Producers and Royalty Owners Association and a member of the Independent Petroleum Association of America and American Association of Petroleum Landmen. Mr. Aikman graduated from the University of Oklahoma in 1952.

*Anthony V. Dub* became a Director in 1995. Mr. Dub is Chairman of Indigo Capital, LLC, a financial advisory firm based in New York City. Prior to forming Indigo Capital in 1997, he served as an officer of Credit Suisse First Boston, an investment banking firm. Mr. Dub joined Credit Suisse First Boston in 1971 and was named a Managing Director in 1981. Mr. Dub received his Bachelor of Arts Degree from Princeton University in 1971.

*Allen Finkelson* became a Director in 1994. Mr. Finkelson has been a partner at Cravath, Swaine & Moore since 1977, with the exception of the period 1983 through 1985, when he was a managing director of Lehman Brothers Kuhn Loeb Incorporated. Mr. Finkelson joined Cravath, Swaine & Moore in 1971. Mr. Finkelson holds a Bachelor of Arts Degree from St. Lawrence University and a Doctor of Laws Degree from Columbia University School of Law.

*Alexander P. Lynch* became a Director in 2000. Mr. Lynch currently serves as a Managing Director of J.P. Morgan, a subsidiary of J.P. MorganChase & Co., and Director of Patina Oil and Gas Corporation. Until its merger into J.P. MorganChase, Mr. Lynch was a General Partner of The Beacon Group. Previously, he was Co-President and Chief Executive Officer of The Bridgeford Group, a financial advisory firm that was acquired by Beacon in 1997. Prior to 1991, Mr. Lynch served as a Managing Director with Lehman Brothers, a division of Shearson Lehman Brothers, Inc. Mr. Lynch received a Bachelor of Arts degree from the University of Pennsylvania and a master's degree from the Wharton School of Business at the University of Pennsylvania.

*James E. McCormick* became a Director in 2000. Mr. McCormick has more than 40 years experience in the oil and gas industry. He currently serves as Director of Lone Star Technologies, TESCO Corporation and Dallas National Bank. He served as a Director for Santa Fe Snyder Corporation until its merger with Devon Energy in August 2000. Mr. McCormick served as President and Chief Operating Officer for Oryx Energy Company from its inception in 1988 until his retirement in 1992. Prior to his position at Oryx, he served as President and Chief Executive Officer of Sun Exploration and Production Company. Mr. McCormick received a Bachelor of Science degree in Geology from Boston University.

*Terry W. Carter,* Executive Vice President-Exploration and Production, joined the Company in January 2001. Previously, Mr. Carter provided consulting services to independent oil and gas companies. From 1976 to 1999, Mr. Carter was employed by Oryx Energy Company, holding a variety of positions including Planning Manager, Development Manager and Manager of Drilling. Mr. Carter received a Bachelor of Science degree in Petroleum Engineering from Tulsa University.

*Eddie M. LeBlanc III,* Senior Vice President and Chief Financial Officer, joined the Company in 2000. Previously Mr. LeBlanc was a founder of Interstate Natural Gas Company, which merged into Coho

Energy in 1994. At Coho Energy Mr. LeBlanc served as Senior Vice President and Chief Financial Officer. Mr. LeBlanc's twenty-six years of experience include assignments in the oil and gas subsidiaries of Celeron Corporation and Goodyear Tire and Rubber. Prior to his industry experience, Mr. LeBlanc was with a national accounting firm, he is a certified public accountant, a chartered financial analyst, and received a Bachelor of Arts degree from University of Southwest Louisiana.

*Herbert A. Newhouse,* Senior Vice President – Gulf Coast, joined the Company in 1998. Prior to joining Range, Mr. Newhouse served as Executive Vice President of Domain Energy Corporation. He was a former Vice President of Tenneco Ventures Corporation. Mr. Newhouse was an employee of Tenneco for over 17 years and has over 30 years of operational and managerial experience in oil and gas exploration and production. Mr. Newhouse received a Bachelor of Science degree in Chemical Engineering from Ohio State University.

*Chad L. Stephens,* Senior Vice President – Southwest, joined the Company in 1990. Previously, Mr. Stephens was with Duer Wagner & Co., an independent oil and gas producer, since 1988. Prior thereto, Mr. Stephens was an independent oil operator in Midland, Texas for four years. From 1979 to 1984, Mr. Stephens was with Cities Service Company and HNG Oil Company. Mr. Stephens received a Bachelor of Arts Degree in Finance and Land Management from the University of Texas.

*Rodney L. Waller,* Senior Vice President and Corporate Secretary, joined the Company in September 1999. Previously, Mr. Waller had been with Snyder Oil Corporation, now part of Devon Energy Corporation, since 1977, where he served as a senior vice president. Before joining Snyder, Mr. Waller was employed by Arthur Andersen. Mr. Waller received a Bachelor of Arts degree from Harding University.

The Board has established four committees to assist it in the discharge of its responsibilities.

*Audit Committee.* The Audit Committee reviews the professional services provided by independent public accountants and the independence of such accountants from management. This Committee also reviews the scope of the audit coverage, the annual financial statements and such other matters with respect to the accounting, auditing and financial reporting practices and procedures as it may find appropriate or as have been brought to its attention. Messrs. Aikman, Dub and Lynch are the members of the Audit Committee.

*Compensation Committee.* The Compensation Committee reviews and approves officers' salaries and administers the bonus, incentive compensation and stock option plans. The Committee advises and consults with management regarding benefits and significant compensation policies and practices. This Committee also considers nominations of candidates for officer positions. The members of the Compensation Committee are Messrs. Aikman, Finkelson and McCormick.

*Dividend Committee.* The Dividend Committee is authorized and directed to approve the payment of dividends. The members of the Dividend Committee are Messrs. Edelman and Pinkerton.

*Executive Committee.* The Executive Committee reviews and authorizes actions required in the management of the business and affairs of Range, which would otherwise be determined by the Board, where it is not practicable to convene the full Board. One of the principal responsibilities of the Executive Committee will be to review and approve smaller acquisitions. The members of the Executive Committee are Messrs. Edelman, Finkelson and Pinkerton.

**ITEM 11. COMPENSATION OF EXECUTIVE OFFICERS AND DIRECTORS**

Information with respect to officers' compensation is incorporated herein by reference to the Company's 2001 Proxy Statement.

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

Information with respect to security ownership of certain beneficial owners and management is incorporated herein by reference to the Company's 2001 Proxy Statement.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

# PART IV

## ITEM 14. EXHIBITS, FINANCIAL STATEMENTS, FINANCIAL STATEMENT SCHEDULES AND REPORTS ON FORM 8-K

(a) 1. and 2. Financial Statements and Financial Statement Schedules

The items listed in the accompanying index to financial statements are filed as part of this Annual Report on Form 10-K.

3. Exhibits.

The items listed on the accompanying index to exhibits are filed as part of this Annual Report on Form 10-K.

(b) Reports on Form 8-K.

None.

(c) Exhibits required by Item 601 of Regulation S-K

Exhibits required to be filed pursuant to Item 601 of Regulation S-K are contained in Exhibits listed in response to Item 14 (a)3, and are incorporated herein by reference.

(d) Financial Statement Schedules Required by Regulation S-X. The items listed in the accompanying index to financial statements are filed as part of this Annual Report on Form 10-K.

## SIGNATURES

**Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.**

Dated: March 5, 2001

**RANGE RESOURCES CORPORATION**

By: /s/ John H. Pinkerton
John H. Pinkerton
President

**Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the persons on behalf of the Company and in the capacities and on the dates indicated.**

| | |
|---|---|
| /s/ Thomas J. Edelman<br>March 5, 2001 | Thomas J. Edelman,<br>Chairman and Chairman of the Board |
| /s/ John H. Pinkerton<br>March 5, 2001 | John H. Pinkerton,<br>President and Director |
| /s/ Eddie M. LeBlanc III<br>March 5, 2001 | Eddie M. LeBlanc III<br>Chief Financial and Accounting Officer |
| /s/ Robert E. Aikman<br>March 5, 2001 | Robert E. Aikman, Director |
| /s/ Allen Finkelson<br>March 5, 2001 | Allen Finkelson, Director |
| /s/ Anthony V. Dub<br>March 5, 2001 | Anthony V. Dub, Director |
| /s/ James E. McCormick<br>March 5, 2001 | James E. McCormick, Director |
| /s/ Alexander P. Lynch<br>March 5, 2001 | Alexander P. Lynch, Director |

## GLOSSARY

The terms defined in this glossary are used throughout this Form 10-K.

*Bbl.* One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

*Bcf.* One billion cubic feet.

*Bcfe.* One billion cubic feet of natural gas equivalents, based on a ratio of 6 Mcf for each barrel of oil, which reflects the relative energy content.

*Credit Facility.* The Range Resources Corporation $225 million revolving bank facility.

*Development well.* A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

*Dry hole.* A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or gas well.

*Exploratory well.* A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

*Gross acres or gross wells.* The total acres or wells, as the case may be, in which a working interest is owned.

*Infill well.* A well drilled between known producing wells to better exploit the reservoir.

*LIBOR.* London Interbank Offer Rate, the rate of interest at which banks offer to lend to one another in the wholesale money markets in the City of London. This rate is a yardstick for lenders involved in high value transactions.

*Mbbl.* One thousand barrels of crude oil or other liquid hydrocarbons.

*Mcf.* One thousand cubic feet.

*Mcf/d.* One thousand cubic feet per day.

*Mcfe.* One thousand cubic feet of natural gas equivalents, based on a ratio of 6 Mcf for each barrel of oil, which reflects the relative energy content.

*Merger.* The acquisition via merger of Domain Energy Corporation by Lomak Petroleum, Inc. in August 1998. Simultaneously, Lomak's name was changed to Range Resources Corporation.

*Mmbbl.* One million barrels of crude oil or other liquid hydrocarbons.

*Mmbtu.* One million British thermal units. One British thermal unit is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

*Mmcf.* One million cubic feet.

*Mmcfe.* One million cubic feet of natural gas equivalents.

*Net acres or net wells.* The sum of the fractional working interests owned in gross acres or gross wells.

*Net oil and gas sales.* Oil and natural gas sales less oil and natural gas production expenses.

*Oil and gas royalty trust.* An arrangement whereby typically, the creating company conveys a net profits interest in certain of its oil and gas properties to the newly created trust and then distributes ownership units in the trust to its unitholders. The function of the trust is to serve as agent to distribute income from the net profits interest to its unitholders.

*Present Value.* The present value, discounted at 10%, of future net cash flows from estimated proved reserves, using constant prices and costs in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions).

*Productive well.* A well that is producing oil or gas or that is capable of production.

*Proved developed non-producing reserves.* Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

*Proved developed producing reserves.* Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

*Proved developed reserves.* Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

*Proved reserves.* The estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

*Proved undeveloped reserves.* Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

*Recompletion.* The completion for production of an existing wellbore in another formation from that in which the well has previously been completed.

*Reserve life index.* The presentation of proved reserves defined in number of years of annual production.

*Royalty interest.* An interest in an oil and gas property entitling the owner to a share of oil and natural gas production free of costs of production.

*Standardized Measure.* The present value, discounted at 10%, of future net cash flows from estimated proved reserves after income taxes calculated holding prices and costs constant at amounts in effect on the date of the report (unless such prices or costs are subject to change pursuant to contractual provisions) and otherwise in accordance with the Commission’s rules for inclusion of oil and gas reserve information in financial statements filed with the Commission.

*Term overriding royalty.* A royalty interest that is carved out of the operating or working interest in a well. Its term does not extend to the economic life of the property and is of shorter duration than the underlying working interest. The term overriding royalties in which the Company participates through its Independent Producer Finance subsidiary typically extend until amounts financed and a designated rate of return have been achieved. At such point in time, the override interest reverts back to the working interest owner.

*Working interest.* The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

**RANGE RESOURCES CORPORATION**

**INDEX TO CONSOLIDATED FINANCIAL STATEMENTS AND SCHEDULES**

**(Item 14[a], [d])**



**Exhibits**

All other schedules have been omitted since the required information is not present in amounts sufficient to require submission of the schedule, or because the information required is included in the financial statements or footnotes.

## REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS

**To The Board of Directors and Stockholders**
**Range Resources Corporation**

We have audited the accompanying consolidated balance sheets of Range Resources Corporation (a Delaware corporation) as of December 31, 1999 and 2000, and the related consolidated statements of income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of Range Resources Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Range Resources Corporation as of December 31, 1999 and 2000, and the results of its operations and its cash flows for the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Dallas, Texas
February 23, 2001

## RANGE RESOURCES CORPORATION

## CONSOLIDATED BALANCE SHEETS

## (In thousands, except per share data)

| | December 31, | |
|---|---|---|
| | **1999** | **2000** |
| **Assets** | | |
| Current assets | | |
| Cash and equivalents | $ 12,937 | $ 2,485 |
| Accounts receivable, net | 21,646 | 33,221 |
| IPF receivables (Note 4) | 12,500 | 20,800 |
| Inventory and other | 9,130 | 5,580 |
| Assets held for sale (Note 5) | 19,660 | — |
| | 75,873 | 62,086 |
| IPF receivables, net (Note 4) | 52,913 | 28,128 |
| Oil and gas properties, successful efforts method (Note 16) | 975,985 | 1,014,939 |
| Accumulated depletion | (383,622) | (443,097) |
| | 592,363 | 571,842 |
| Transportation and field assets (Note 2) | 33,777 | 33,593 |
| Accumulated depreciation | (10,572) | (12,339) |
| | 23,205 | 21,254 |
| Other (Note 2) | 8,014 | 5,855 |
| | $ 752,368 | $ 689,165 |
| **Liabilities and Stockholders' Equity** | | |
| Current liabilities | | |
| Accounts Payable | $ 23,925 | $ 26,730 |
| Accrued liabilities | 16,074 | 11,341 |
| Accrued interest | 8,635 | 7,774 |
| Current portion of long-term debt (Note 6) | 5,014 | 14 |
| | 53,648 | 45,859 |
| Senior debt (Note 6) | 135,000 | 89,900 |
| Non-recourse debt (Note 6) | 142,520 | 113,009 |
| Subordinated notes (Note 6) | 176,360 | 162,550 |
| Commitments and contingencies (Note 8) | | |
| Company-obligated preferred securities of subsidiary trust (Note 6) | 117,669 | 92,640 |
| Stockholders' equity (Notes 9 and 10) | | |
| Preferred stock, $1 par, 10,000,000 shares authorized, $2.03 convertible preferred, 1,149,840 and 219,935 issued and outstanding, respectively (liquidation preference $28,746,000 and $5,498,375, respectively) | 1,150 | 220 |
| Common stock, $.01 par, 100,000,000 shares authorized, 37,901,789 and 49,187,682 issued and outstanding, respectively | 379 | 492 |
| Capital in excess of par value | 340,279 | 363,625 |
| Retained earnings (deficit) | (214,630) | (178,223) |
| Other comprehensive income (loss) | (7) | (907) |
| | 127,171 | 185,207 |
| | $ 752,368 | $ 689,165 |

**See accompanying notes.**

# RANGE RESOURCES CORPORATION

## CONSOLIDATED STATEMENTS OF INCOME

### (In thousands, except per share data)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 1998 | 1999 | 2000 |
| Revenues | | | |
| Oil and gas sales | $ 135,593 | $145,492 | $173,082 |
| Transportation and processing, net | 6,711 | 7,770 | 5,306 |
| IPF income | 4,370 | 7,872 | 10,033 |
| Interest and other | 2,255 | 420 | (702) |
| Gain on formation of Great Lakes (Note 18) | — | 39,810 | — |
| | 148,929 | 201,364 | 187,719 |
| Expenses | | | |
| Direct operating | 39,001 | 43,074 | 38,525 |
| IPF | 7,996 | 5,825 | 4,865 |
| Exploration | 11,265 | 2,409 | 3,187 |
| General and administrative | 9,215 | 8,028 | 10,323 |
| Interest | 40,642 | 47,085 | 39,953 |
| Depletion, depreciation and amortization | 60,153 | 76,447 | 72,242 |
| Provision for impairment | 207,128 | 27,118 | — |
| Restructuring costs (Note 13) | 3,147 | — | — |
| | 378,547 | 209,986 | 169,095 |
| Income (loss) before taxes | (229,618) | (8,622) | 18,624 |
| Income taxes | | | |
| Current | 278 | 1,601 | (1,574) |
| Deferred | (54,746) | — | — |
| | (54,468) | 1,601 | (1,574) |
| Income (loss) before extraordinary item | (175,150) | (10,223) | 20,198 |
| Extraordinary item | | | |
| Gain on retirement of securities, net (Note 19) | — | 2,430 | 17,763 |
| Net income (loss) | $(175,150) | $ (7,793) | $ 37,961 |
| Comprehensive income (loss) (Note 2) | $(175,260) | $ (8,566) | $ 37,061 |
| Earnings (loss) per share before extraordinary item: (Note 14) Basic and diluted | $ (6.82) | $ (0.34) | $ 0.57 |
| Earnings (loss) per share after extraordinary item: (Note 14) Basic and diluted | $ (6.82) | $ (0.27) | $ 0.99 |

**See accompanying notes.**

## RANGE RESOURCES CORPORATION

## CONSOLIDATED STATEMENTS OF CASH FLOWS

## (In thousands)

| | Year Ended December 31, | | |
|---|---|---|---|
| | 1998 | 1999 | 2000 |
| **Cash flows from operations:** | | | |
| Net income (loss) | $(175,150) | $ (7,793) | $ 37,961 |
| Adjustments to reconcile net income (loss) to net cash provided by operations: | | | |
| Depletion, depreciation and amortization | 60,153 | 76,447 | 72,242 |
| Provision for impairment | 207,128 | 27,118 | — |
| Allowance for IPF receivables | 5,918 | 3,962 | (1,299) |
| Amortization of deferred offering costs | 1,293 | 1,333 | 2,020 |
| Deferred income taxes | (54,746) | — | — |
| Gain on conversion of securities | — | (2,430) | (17,978) |
| (Gain) loss on sale of assets and other | (1,817) | (39,280) | 1,116 |
| Changes in working capital net of effects of acquired businesses: | | | |
| Accounts receivable | 2,842 | 8,738 | (11,601) |
| Marketable securities | (253) | (35) | — |
| Inventory and other | 6,996 | (1,958) | (334) |
| Accounts payable | (4,274) | (7,560) | (3,674) |
| Accrued liabilities | (3,068) | (8,355) | (4,345) |
| Net cash provided by operations | 45,022 | 50,187 | 74,108 |
| **Cash flows from investing:** | | | |
| Acquisition of businesses, net of cash | (41,170) | — | — |
| Investment in Great Lakes | — | 98,715 | — |
| Oil and gas properties | (135,399) | (25,093) | (46,763) |
| Field service assets | (3,732) | (656) | (2,263) |
| IPF investments | (12,649) | (5,362) | (6,985) |
| IPF repayments | 3,556 | 13,160 | 24,764 |
| Proceeds from sales of assets | 17,081 | 17,476 | 25,944 |
| Net cash (used in) provided by investing | (172,313) | 98,240 | (5,303) |
| **Cash flows from financing**: | | | |
| Proceeds from indebtedness | 135,375 | — | — |
| Repayments of indebtedness | — | (145,129) | (79,611) |
| Preferred dividends | (2,334) | (2,334) | (1,444) |
| Common dividends | (3,500) | (1,107) | — |
| Issuance of common stock | 1,985 | 2,152 | 1,798 |
| Repurchase of common stock | (3,006) | (26) | — |
| Net cash provided by (used in) financing | 128,520 | (146,444) | (79,257) |
| Change in cash | 1,229 | 1,983 | (10,452) |
| Cash and equivalents, beginning of year | 9,725 | 10,954 | 12,937 |
| Cash and equivalents, end of year | $ 10,954 | $ 12,937 | $ 2,485 |

**See accompanying notes.**

## RANGE RESOURCES CORPORATION

## CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

## (In thousands)

| | Preferred Stock | | Common Stock | | | | |
|---|---|---|---|---|---|---|---|
| | Shares | Par Value | Shares | Par Value | Capital in Excess of Par Value | Retained Earnings (Deficit) | Other Comprehensive Income (loss) |
| **Balance, December 31, 1997** | 1,150 | $1,150 | 21,058 | $211 | $217,631 | $ (22,412) | $ 370 |
| Preferred dividends | — | — | — | — | — | (2,334) | — |
| Common dividends | — | — | — | — | — | (3,500) | — |
| Issuance of common | — | — | 15,276 | 152 | 120,188 | — | — |
| Repurchase of common | — | — | (401) | (4) | (3,002) | — | — |
| Unrealized loss on investments | — | — | — | — | — | — | (78) |
| Net loss | — | — | — | — | — | (175,150) | — |
| **Balance, December 31, 1998** | 1,150 | 1,150 | 35,933 | 359 | 334,817 | (203,396) | 292 |
| Preferred dividends | — | — | — | — | — | (2,334) | — |
| Common dividends | — | — | — | — | — | (1,107) | — |
| Issuance of common | — | — | 1,270 | 13 | 2,113 | — | — |
| Conversion of securities | — | — | 699 | 7 | 3,349 | — | — |
| Unrealized loss on investments | — | — | — | — | — | — | (299) |
| Net loss | — | — | — | — | — | (7,793) | — |
| **Balance, December 31, 1999** | 1,150 | 1,150 | 37,902 | 379 | 340,279 | (214,630) | (7) |
| Preferred dividends | — | — | — | — | — | (1,554) | — |
| Issuance of common | — | — | 974 | 10 | 2,713 | — | — |
| Conversion of securities | (930) | (930) | 10,312 | 103 | 20,633 | — | — |
| Unrealized loss on investments | — | — | — | — | — | — | (900) |
| Net income | — | — | — | — | — | 37,961 | — |
| **Balance, December 31, 2000** | 220 | $ 220 | 49,188 | $492 | $363,625 | $(178,223) | $(907) |

**See accompanying notes.**

## RANGE RESOURCES CORPORATION

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

### (1) ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation (“Range”) is an independent oil and gas company engaged in development, acquisition and exploration primarily in the Southwest, Gulf Coast and Appalachian regions of the United States. In addition, the Company provides financing to smaller oil and gas producers through a wholly-owned subsidiary, Independent Producer Finance (“IPF”), by purchasing overriding royalty interests. Historically, the Company has sought to increase its reserves and production primarily through development drilling and acquisitions.

In September 1999, Range and FirstEnergy Corp. (“FirstEnergy”) contributed their Appalachian oil and gas properties to Great Lakes Energy Partners L.L.C. (“Great Lakes”). To equalize their interests, Great Lakes assumed $188.3 million of indebtedness from Range and FirstEnergy contributed $2.0 million of cash.

A series of significant acquisitions financed principally with debt and convertible fixed income securities were completed between late 1997 and mid 1998. Due to the poor performance of the acquired properties, the Company was forced to take a number of steps. These included a sharp reduction in staff, a significant decrease in capital expenditures, the sale of assets, the formation of Great Lakes and initiation of an effort to exchange common stock for fixed income securities. Since year-end 1998, these initiatives have reduced parent company bank debt by 75% to $89.9 million. Total debt (including Trust Preferred) has been reduced 37% to $458.1 million. While management believes these steps have stabilized the Company’s financial position, total debt remains too high. For the Company to return to its historical posture of consistent profitability and growth, management believes it necessary to further reduce debt. The Company expects to utilize excess cash flow to retire debt and to continue to exchange common stock or other equity-linked securities for fixed income securities. While the Company expects to reacquire the fixed income securities at a discount to face value, existing stockholders will be substantially diluted if a material portion of the fixed income securities are exchanged. The extent of dilution will depend on a number of factors, including the number of shares issued, the price at which stock is issued or newly issued securities are convertible into common stock and the price at which fixed income securities are reacquired. While such exchanges reduce existing stockholders’ proportionate ownership, management believes such exchanges enhance the Company’s financial flexibility and should increase the market value of its common stock.

While the Company currently believes it has sufficient liquidity and cash flow to meet its obligations, a material drop in oil and gas prices or a reduction in production and reserves would reduce the Company’s ability to fund capital expenditures, reduce debt and meet its financial obligations.

The Company operates in an environment with numerous financial and operating risks, including, but not limited to, the ability to acquire reserves, the inherent risks of the search for, development and production of oil and gas, the ability to sell production at prices which provide an attractive return and the highly competitive nature of the industry. The Company’s ability to expand its reserve base is dependent on obtaining the necessary capital through internal cash flow, borrowings or the issuance of debt or equity securities.

### (2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

#### Basis of Presentation

The accompanying consolidated financial statements include the accounts of the Company, all majority-owned subsidiaries and a pro rata share of the assets, liabilities, income and expenses of Great

Lakes. Liquid investments with maturities of ninety days or less are considered cash equivalents.

**Revenue Recognition**

The Company recognizes revenues from the sale of products and services in the period they are delivered. Revenues at IPF are recognized in the period received. Although its receivables are concentrated in the oil and gas industry, the Company does not view this concentration as an unusual credit risk. In addition to IPF's valuation allowances, the Company had allowances for doubtful accounts of $1.5 million and $1.7 million at December 31, 1999 and 2000, respectively.

**Marketable Securities**

The Company has adopted SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities," pursuant to which debt and marketable equity securities are classified in three categories: trading, available-for-sale, or held-to-maturity. The Company's equity securities qualify as available-for-sale. Such securities are recorded at fair value and unrealized gains and losses are reflected in Stockholders' Equity as a component of comprehensive income. A decline in the market value of a security below cost that is deemed other than temporary is charged to earnings and reflected in the book value of the security. Realized gains and losses are determined on the specific identification method and reflected in income. In 1998, certain securities classified as available for sale were written down by $10.3 million to their estimated realizable value, because in the opinion of management, the decline in market value was considered to be other than temporary.

**Great Lakes**

As noted above, the Company contributed its Appalachian assets to Great Lakes in September 1999, retaining a 50% interest in the venture. Great Lakes' proved reserves, 85% of which are natural gas, approximated 481 Bcfe at December 31, 2000. In addition, Great Lakes owns 4,700 miles of gas gathering and transportation lines and a leasehold position of approximately 1.1 million gross (992,000 net) acres. To date, the joint venture has identified over 1,600 proved drilling locations within its existing fields. Great Lakes has a reserve life index of 20 years.

**Independent Producer Finance**

IPF acquires dollar denominated term overriding royalties in oil and gas properties from smaller producers. These royalties are accounted for as receivables because the investment is recovered from an agreed-upon share of revenues until a specified rate of return is received. The portion of payments received relating to the return is recognized as income; remaining receipts reduce receivables and are reported as a return of capital on the statement of cash flows. Receivables classified as current are those expected to be received within twelve months. Periodically, IPF's receivables are reviewed and provisions for amounts believed uncollectible are established. At December 31, 2000, the valuation allowance totaled $15.3 million. In addition, IPF calculates income on certain of its receivables at rates of return below that specified in the relevant contracts where an analysis of the underlying assets suggests that to be prudent. During 1999 and 2000 IPF expenses were comprised of $1.5 million and $1.5 million of general and administrative costs and $4.3 million and $3.4 million of interest, respectively. IPF recorded valuation allowances of $3.3 million and $603,000 against its revenues in 1999 and first quarter 2000. However, because of higher product prices and the resultant increase in cash receipts, IPF reversed $1.9 million of previously reserved amounts over the remaining quarters of 2000.

**Oil and Gas Properties**

The Company follows the successful efforts method of accounting for its oil and gas properties. Exploratory drilling costs are capitalized pending determination of whether a well is successful. Exploratory drilling costs which result in discoveries and development costs are capitalized. Geological and geophysical costs, delay rentals and costs to drill unsuccessful exploratory wells are expensed.

Depletion is provided on the unit-of-production method. Oil is converted to Mcfe at the rate of six Mcf per barrel. The depletion rates were $0.89, $1.04 and $1.30 per Mcfe in 1998, 1999 and 2000, respectively. Unproved properties had a net book value of $75.9 million, $61.8 million and $49.5 million at December 31, 1998, 1999 and 2000, respectively.

The Company has adopted SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets", which establishes accounting standards for the impairment of long-lived assets, certain identifiable intangibles and goodwill. SFAS No. 121 requires a review for impairment whenever circumstances indicate that the carrying amount of an asset may not be recoverable. In performing the review for recoverability during 1998 and 1999, the Company recorded provisions for impairment of $196.8 million and $6.1 million, respectively, which reduced the carrying value of certain oil and gas properties to what the Company estimated to have been their fair value at the time. The provisions for impairment on the oil and gas properties were due to downward reserve revisions resulting from production declines substantially in excess of those anticipated, and disappointing drilling results in certain of the same fields and to a lesser degree, declines in oil and gas prices in 1998 and 1999. The impairment on proven properties was determined based on the difference between the carrying amount of the assets and the present value of the future cash flows from proved reserves discounted at 10%. Impairment is recognized only if the carrying amount of a property is greater than its expected undiscounted future cash flows. While management believes it has fully reflected the adverse impact of known reserve disappointments, it is possible that a change in reserve estimates could occur in the future and adversely impact management's estimate of future cash flows and consequently the carrying value of the properties. The following are the proved properties impaired during 1998 (in thousands):

| Property | Impairment |
|---|---|
| Southwest | $ 68,236 |
| Gulf Coast – offshore | 62,400 |
| Appalachia | 14,644 |
| Gulf Coast – onshore | 2,323 |
| | $147,603 |

Unproved properties are assessed periodically to determine whether there has been a decline in value. If such decline is indicated, a loss is recognized. The Company compares the carrying value of its unproved properties to their estimated fair value, using information as the Company's geological assessment of the acreage and other acreage purchases in the area. The following unproved properties were impaired during 1998 (in thousands):

| Property | Impairment |
|---|---|
| Sonora acreage | $20,089 |
| South Texas acreage | 19,922 |
| Offshore acreage | 9,177 |
| | $49,188 |

During 1999, the Company recorded a $6.1 million impairment of unproved acreage in the Gulf of Mexico due to further evaluations based on updated production and technical data indicating a reduction in the number of economic drilling locations. The amount of impairment was calculated by determining fair value at December 31, 1999 using management's best estimate of the remaining value of these properties.

### Transportation, Processing and Field Assets

The Company's gas gathering systems are located in proximity to certain of its principal fields. Depreciation on these systems is provided on the straight-line method based on estimated useful lives of four to fifteen years. The Company sold its only remaining gas processing facility, the Sterling Plant, in June 2000. See Note 5.

The Company receives fees for providing certain field services. These fees are recognized as earned. Depreciation on the associated assets is calculated on the straight-line method based on estimated useful lives ranging from one to five years. Buildings are depreciated over seven to twenty-five years.

### Security Issuance Costs

Expenses associated with the issuance of debt and trust preferred securities are capitalized and included in Other Assets on the balance sheet. These costs are being amortized on the effective interest method over the expected life of the related security. When a security is reacquired prior to maturity, related unamortized issuance costs are expensed.

### Gas Imbalances

The Company uses the sales method to account for gas imbalances, recognizing revenue based on cash received rather than the proportionate share of gas produced. At December 31, 2000, the Company had recorded a gas imbalance liability of $318,000, which is included in Accrued Liabilities on the balance sheet.

### Comprehensive Income

The Company has adopted SFAS No. 130, "Reporting Comprehensive Income," requiring the disclosure of comprehensive income and its components. Comprehensive income is defined as changes in stockholders' equity from nonowner sources including net income and changes in the fair value of marketable securities. The following is a calculation of comprehensive income for each of the three years in the period ended December 31, 2000 (in thousands).

| | Year Ended December 31, | | |
|---|---|---|---|
| | **1998** | **1999** | **2000** |
| Net income (loss) | $(175,150) | $(7,793) | $37,961 |
| Add: Change in unrealized gain/(loss) | | | |
| Gross | (78) | (299) | (900) |
| Tax effect | 19 | — | — |
| Less: Realized gain/(loss) | | | |
| Gross | (66) | (474) | — |
| Tax effect | 15 | — | — |
| Comprehensive income (loss) | $(175,260) | $(8,566) | $37,061 |

Based on oil and gas hedging contracts in place at December 31, 2000, an additional $72.1 million of comprehensive loss would be recognized at December 31, 2000 had the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," been in effect on that date. See "Recent Accounting Pronouncements" below.

**Use of Estimates**

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities and the reported amounts of revenues and expenses. Actual results could differ from those estimates.

**Recent Accounting Pronouncements**

In 1998, the Financial Accounting Standards Board ("FASB") issued SFAS No. 133. In 1999, the FASB issued SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities – Deferral of the Effective Date of FASB Statement No. 133." In 2000, the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of FASB Statement No. 133."

SFAS No. 133, as amended, establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows a derivative instrument's gains and losses to offset related results on the hedged item in the income statement, to the extent effective, and requires that a company formally document, designate and assess the effectiveness of transactions that receive hedge accounting. SFAS No. 133, as amended, is effective for fiscal years beginning after June 15, 2000. It cannot be applied retroactively.

The Company adopted SFAS No. 133 on January 1, 2001. As discussed in the following paragraphs, SFAS No. 133 will almost certainly increase volatility in earnings and other comprehensive income.

SFAS No. 133, in part, allows special hedge accounting for *fair value* and *cash flow* hedges. The gain or loss on a derivative instrument designated and qualifying as a *fair value* hedging instrument as well as the offsetting loss or gain on the hedged item attributable to the hedged risk must be recognized currently in earnings in the same accounting period. The effective portion of the gain or loss on a derivative instrument designated and qualifying as a *cash flow* hedging instrument must be reported as a component of other comprehensive income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, must be recognized currently in earnings.

The Company enters into interest rate swap agreements to reduce the risk of changes in the debt's fair value attributable to changes in the LIBOR rate. These swap agreements qualify as fair value hedges. Accordingly, income or expense resulting from such agreements is recorded as an adjustment to interest expense in the period covered. The Company also enters into fixed–price contracts to reduce the effects of fluctuations in oil and gas prices. These fixed-price contracts qualify as cash flow hedges. Prior to the adoption of SFAS No. 133 on January 1, 2001, gains and losses were determined monthly and were included in oil and gas revenues in the period the hedged production was sold. With the adoption of SFAS No. 133 in 2001, gains or losses will be recorded as described in the preceding paragraph.

SFAS No. 133 requires the Company to evaluate its commodity contracts to determine whether they are "normal purchases or normal sales." Certain contracts do not meet SFAS No. 133's definition of "normal purchases or normal sales" and therefore are considered derivative instruments. However, the contracts that do not meet the definition of "normal purchases or normal sales" may be designated as cash flow hedges of the underlying commodity sales.

Based on such contracts in effect on December 31, 2000, derivative liabilities of approximately $72.1 million would be recognized in the balance sheet with an offsetting amount deferred in accumulated other comprehensive loss. See Note 7.

### Reclassifications

Certain reclassifications have been made to the presentation of prior periods to conform with current classifications.

### (3) ACQUISITIONS

All acquisitions have been accounted for as purchases. Purchase prices were allocated to acquired assets based on their estimated fair value at acquisition. Acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities.

In March 1998, oil and gas properties in the Powell Ranch Field in West Texas were acquired for $60 million, comprised of $54.6 million in cash and $5.4 million of common stock.

In September 1998, the Company completed the acquisition via merger of Domain Energy Corporation (“Domain”) for $161.6 million, comprised of $50.5 million in cash and $111.1 million of common stock. Domain’s principal assets included oil and gas operations primarily onshore in the Gulf Coast and in the Gulf of Mexico, as well as IPF.

In addition to the above mentioned acquisitions, the Company purchased various other properties for consideration of $2.7 million, $0.8 million and $4.7 million during the years ended December 31, 1998, 1999 and 2000, respectively.

### Unaudited Pro Forma Financial Information

The following table presents unaudited pro forma operating results as if the Great Lakes transaction and sale of the Sterling Plant had occurred on January 1, 1999 (in thousands, except per share data).

| | Pro Forma Year ended December 31, | |
|---|---|---|
| | **1999** | **2000** |
| Revenues | $190,225 | $185,574 |
| Net income (loss) | (27,444) | 38,262 |
| Earnings (loss) per share – basic and diluted | (0.80) | 1.00 |
| Total assets | 728,583 | 686,518 |
| Stockholders’ equity | 105,329 | 182,326 |

The pro forma results have been prepared for comparative purposes only and do not purport to present actual results that would have been achieved had the acquisitions, divestitures and financings been made on January 1, 1999 or to be indicative of future results.

### (4) IPF RECEIVABLES

At December 31, 1999 and 2000, IPF had net receivables of $65.4 million and $48.9 million, respectively. The receivables result from the purchase of term overriding royalty interests payable from an agreed-upon share of revenues until a specified rate of return has been achieved. The royalties constitute property interests that serve as security for the receivables. The Company estimates that $20.8 million of receivables at December 31, 2000 will be repaid in the next twelve months and has classified them as current. The net receivables reflect valuation allowances for estimated uncollectible amounts of $17.3 million and $15.3 million at December 31, 1999 and 2000, respectively.

## (5) DISPOSITIONS

At December 31, 1999, assets held for sale consisted of the Sterling Plant. In September 1999, when the decision to sell the plant was reached, it was determined that the plant's carrying value exceeded fair value and an impairment of $21.0 million was recognized. In June 2000, the Company sold the Plant and recorded an additional $716,000 loss.

## (6) INDEBTEDNESS

The Company had the following debt and company-obligated preferred securities of subsidiary trust outstanding as of the dates shown. Interest rates, excluding the impact of interest rate swaps, at December 31, 2000 are shown parenthetically:

| | December 31, | |
|---|---|---|
| | 1999 | 2000 |
| | (In thousands) | |
| **Senior debt** | | |
| Credit Facility (8.8%) | $140,000 | $ 89,900 |
| Other (6.2%) | 14 | 14 |
| | 140,014 | 89,914 |
| Less amounts due within one year | (5,014) | (14) |
| Senior debt, net | 135,000 | 89,900 |
| **Non-recourse debt** | | |
| Great Lakes credit facility (8.6%) | 95,020 | 84,509 |
| IPF credit facility (9.0%) | 47,500 | 28,500 |
| Non-recourse debt | 142,520 | 113,009 |
| **Subordinated notes** | | |
| 8.75% Senior Subordinated Notes due 2007 | 125,000 | 125,000 |
| 6% Convertible Subordinated Debentures due 2007 | 51,360 | 37,550 |
| Subordinated notes | 176,360 | 162,550 |
| Total debt | $453,880 | $365,459 |
| **5.75% Convertible Trust Preferred** | 117,669 | 92,640 |
| **Total debt and Trust Preferred** | $571,549 | $458,099 |

Interest paid (including IPF) during the years ended December 31, 1999 and 2000 totaled $47.1 million and $42.2 million, respectively. The Company does not capitalize interest expense.

**Senior debt**

The Company maintains a $225 million secured revolving bank facility (the “Credit Facility”). The Credit Facility provides for a borrowing base which is subject to redeterminations semi-annually in April and October and under certain other conditions. On March 1, 2001, the borrowing base on the Credit Facility was $115 million of which $21.1 million was available. Redeterminations are based on a variety of factors, including the discounted present value of the banks’ projection of estimated future net cash flows. Borrowing base redeterminations require approval by 75% of the lenders. Interest is payable the earlier of quarterly or as LIBOR notes mature. The loan matures in February 2003. A commitment fee is paid quarterly on the undrawn balance at a rate of 0.25% to 0.50%. The interest rate on the Credit Facility is LIBOR plus 1.50% to 2.25%, depending on amounts outstanding. The weighted average interest rates on these borrowings, excluding interest rate swaps, were 7.1% and 8.8% for the years ended December 31, 1999 and 2000, respectively.

**Non-recourse debt**

The Company consolidates its proportionate share of the amount outstanding under Great Lakes’ $275 million revolving bank facility (the “Great Lakes Facility”). The Great Lakes Facility is non-recourse to Range and provides for a borrowing base, which is subject to redeterminations semi-annually in April and October and is secured by oil and gas properties. On March 1, 2001, the borrowing base was $200 million of which $40 million was available. Interest is payable the earlier of quarterly or as LIBOR notes mature. The loan matures in September 2002. The interest rate on the facility is LIBOR plus 1.50% to 2.00%, depending on amounts outstanding. A commitment fee is paid quarterly on the undrawn balance at a rate of 0.25% to 0.50%. The weighted average interest rates on these borrowings were 7.7% and 8.6% for the years ended December 31, 1999 and 2000, respectively.

IPF has a $100 million revolving credit facility (the “IPF Facility”). The IPF Facility is non-recourse to Range and is secured by IPF’s assets. The IPF Facility matures in December 2002. The borrowing base under the IPF Facility is subject to semi-annual redeterminations. On March 1, 2001, the borrowing base on the IPF Facility was $37 million of which $13.6 million was available. The IPF Facility bears interest at LIBOR plus 1.75% to 2.25% depending on amounts outstanding. Interest expense in the IPF Facility is included in IPF expenses in the Statements of Income and amounted to $4.3 million and $3.4 million for the years ended December 31, 1999 and 2000, respectively. A commitment fee is paid quarterly on the undrawn balance at a rate of 0.375% to 0.50%. The weighted average interest rate on these borrowings was 7.0% and 8.5% for the years ended December 31, 1999 and 2000, respectively.

**Subordinated Notes**

The 8.75% Senior Subordinated Notes due 2007 (the “8.75% Senior Notes”) are not redeemable until January 15, 2002. Thereafter, they are redeemable at the option of the Company, in whole or in part, at prices beginning at 104.375% of principal, declining to par in 2005. The 8.75% Senior Notes are unsecured general obligations and are subordinated to all senior debt (as defined) including borrowings under the Credit Facility. The 8.75% Senior Notes are guaranteed on a senior subordinated basis by the Company’s subsidiaries. Interest is payable semi-annually in January and July.

The 6% Convertible Subordinated Debentures Due 2007 (the “6% Debentures”) are convertible into common stock at the option of the holder at any time at a price of $19.25 per share, subject to adjustment in certain events. Interest is payable semi-annually in February and August. The 6% Debentures mature in 2007 and at December 31, 2000 were redeemable at 104% of principal amount, declining 0.5% annually each February through 2007. The 6% Debentures are unsecured general obligations and are subordinated to all senior indebtedness (as defined), including the 8.75% Notes and the Credit Facility. During 1999 and 2000, $3.6 million and $13.8 million of 6% Debentures were retired at a discount in exchange for 496,000 and 2.5 million shares of common stock, respectively. Extraordinary gains of $1.2 million and $4.3 million were recorded in 1999 and 2000, respectively.

### Trust Preferred

In 1997, the Lomak Financing Trust (the “Trust”), a special purpose affiliate, issued $120 million of 5 3/4% Trust Convertible Preferred Securities (the “Trust Preferred”), represented by 2,400,000 shares of Trust Preferred priced at $50 a share. Each Trust Preferred share is convertible at the holder’s option into 2.1277 shares of common stock, representing a conversion price of $23.50 per share.

The Trust invested the $120 million of proceeds in 5 3/4% convertible junior subordinated debentures issued by the Company (the “Junior Debentures”). The sole assets of the Trust are the Junior Debentures. The Junior Debentures and the related Trust Preferred mature in November 2027. At December 31, 2000, the Junior Debentures and the related Trust Preferred could be redeemed in whole or in part at a price of 104.025% of principal. The redemption price declines annually in November through 2007, when it reaches par. If any Junior Debentures are redeemed prior to maturity, the Trust must simultaneously redeem an equal amount of Trust Preferred.

The Company has guaranteed payments on the Trust Preferred only to the extent the Trust has funds available. Such guarantee, when taken together with Range’s obligations under the Junior Debentures and related indenture and declaration of trust, provide a full and unconditional subordinated guarantee of the Trust Preferred. The accounts of the Trust are included in Range’s Consolidated Financial Statements after appropriate eliminations of intercompany balances. Distributions on the Trust Preferred are recorded as interest expense on the Consolidated Statements of Income and are deductible for tax purposes. These distributions are subject to limitations in the Credit Facility as described below.

In 1999 and 2000, $2.3 million and $25.0 million of Trust Preferred were exchanged for 202,000 and 3.2 million shares of common stock, respectively. Extraordinary gains of $1.3 million and $13.5 million, respectively, were recorded as the Trust Preferred was retired at a discount.

The debt agreements contain various covenants relating to net worth, working capital maintenance, restrictions on dividends and financial ratio requirements. If certain ratio requirements are not met, payments of interest on the Trust Preferred and/or dividends on the $2.03 Preferred would be restricted. The bank credit facility prohibits the payment of dividends on common stock. The Company was in compliance with all such covenants at December 31, 2000. Under the most restrictive dividend covenant, the Company had the ability to pay only $4.9 million of dividends or other restricted payments at December 31, 2000.

## (7) FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

The Company’s financial instruments include cash and equivalents, accounts receivable, accounts payable, debt obligations, commodity and interest rate futures, options, and swaps. The book value of cash and equivalents, accounts receivable and payable and short-term debt are considered to be representative of fair value because of their short maturity. The Company believes that the carrying value of its borrowings under the Credit Facility and the Great Lakes and IPF Facilities (collectively “the Bank Facilities”) approximate fair value because of their floating rate structure.

A portion of the Company’s anticipated future oil and gas sales is periodically hedged against price risks through the use of futures, option or swap contracts. Gains and losses on these instruments are reflected in the contract month being hedged as an adjustment to oil and gas revenue. At times, the Company seeks to manage interest rate risk on its credit facilities through the use of interest rate swap agreements. Gains and losses on such agreements are included as an adjustment to interest expense over the period covered.

The following table sets forth the book and estimated fair values of the Company's financial instruments:

| | December 31, 1999 | | December 31, 2000 | |
|---|---|---|---|---|
| | **Book Value** | **Fair Value** | **Book Value** | **Fair Value** |
| Assets | | | | |
| Cash and equivalents | $ 12,937 | $ 12,937 | $ 2,485 | $ 2,485 |
| Marketable securities | 5,079 | 4,756 | 2,028 | 2,028 |
| Commodity swaps | — | 339 | — | — |
| Interest rate swaps | — | 704 | — | — |
| Total asset instruments | 18,016 | 18,736 | 4,513 | 4,513 |
| Liabilities | | | | |
| Commodity swaps | — | — | — | 72,090 |
| Interest rate swaps | — | — | — | 879 |
| Long-term debt | 458,894 | 428,708 | 365,459 | 348,257 |
| Trust Preferred | 117,669 | 45,632 | 92,640 | 53,268 |
| Total liability instruments | 576,563 | 474,340 | 458,099 | 474,494 |
| Net financial instruments | $(558,547) | $(455,604) | $(453,586) | $(469,981) |

At December 31, 2000, the Company had open hedging contracts covering 33.7 Bcf of gas and 1.0 million barrels of oil at prices ranging from $2.84 to $6.78 per Mmbtu (averaging $4.07 per Mmbtu) and $26.96 to $33.71 per barrel (averaging $28.62 per barrel). While these transactions have no carrying value, their fair value, represented by the estimated amount that would be required to terminate the contracts, was a net loss of approximately $72.1 million at December 31, 2000. Due to the decline in commodity prices, particularly natural gas, subsequent to year end, the fair market value of these hedge transactions was a net loss of $54.5 million at February 28, 2001. These contracts expire monthly through December 2002. Gains or losses on hedging transactions are determined as the difference between the contract price and the reference price, generally closing prices on the New York Mercantile Exchange. Transaction gains and losses are determined monthly and are included in oil and gas revenues in the period the hedged production is sold. Net gains or (losses) incurred relating to these derivatives for the years ended December 31, 1998, 1999 and 2000 approximated $3.1 million, $(10.6) million and $(43.2) million, respectively.

In June 2000, the Company repriced 4.1 Bcf of natural gas hedges from an average price of $2.59 per Mmbtu to $3.00 per Mmbtu. In exchange for such repricing, the Company hedged an average of 22,700 Mmbtu per day from April 2001 through March 2002 at an average price of $3.20 per Mmbtu. While the Company’s payment requirement for the repriced hedges was affected, under generally accepted accounting principles the $6.0 million of estimated net losses on the repriced transactions have been recorded in the period in which they would have been recorded if no repricing had occurred. Additionally, a deferred loss and associated liability of $6.0 million were recorded on the Balance Sheet at June 30, 2000, of which $665,000 and $945,000 remained at December 31, 2000, respectively. The imputed interest cost to the Company for repricing the transactions was $168,000. The following schedule shows the effect of the Company’s hedge position for the two quarters ended December 31, 2000 and at December 31, 2000 including the repriced hedges.

| | **Hedging Gain (Loss) Exposure** | | |
|---|---|---|---|
| | | **(In thousands)** | |
| **Quarter Ended** | **Impact on Oil & Gas Revenue** | **Repricing’s Impact on Cash Flow** | **Impact on Cash Flow** |
| Closed contracts: | | | |
| September 30, 2000 | $ (17,668) | $ 1,527 | $ (16,141) |
| December 31, 2000 | (13,996) | 51 | (13,945) |
| | (31,664) | 1,578 | (30,086) |
| Open Contracts: | | | |
| March 31, 2001 | (38,644) | 102 | (38,542) |
| June 30, 2001 | (11,737) | (461) | (12,198) |
| September 30, 2001 | (9,655) | (466) | (10,121) |
| December 31, 2001 | (8,562) | (466) | (9,028) |
| March 31, 2002 | (3,844) | (455) | (4,299) |
| June 30, 2002 | 105 | — | 105 |
| September 30, 2002 | 124 | — | 124 |
| December 31, 2002 | 123 | — | 123 |
| | (72,090) | (1,746) | (73,836) |
| Total | $(103,754) | $ (168) | $(103,922) |

Interest rate swap agreements are accounted for on the accrual basis. Income or expense resulting from these agreements is recorded as an adjustment to interest expense in the period covered. At December 31, 2000, the Company had $20 million of borrowings subject to an interest rate swap agreement at 5.59% which expires in October 2001. The agreement requires that the Company pay the counterparty interest at the above rate and requires the counterparty to pay the Company interest at the 30-day LIBOR rate. In addition, Great Lakes had four interest rate swap agreements totaling $65 million. Two agreements totaling $45 million at rates of 7.09% each expire in May 2004. Two agreements of $10 million each at 6.20% and 6.22% expire in December 2002. The agreements expiring in May 2004 and December 2002 may be terminated at the counterparty’s option in May 2002 and December 2001, respectively. On December 31, 2000, the 30-day LIBOR rate was 6.5%. The fair value of the interest rate swap agreements at December 31, 2000 is based on then current quotes for equivalent agreements. As discussed in Note 6, interest on the Credit Facility is based on LIBOR plus a margin.

These hedging activities are conducted with major financial or commodities trading institutions which management believes are acceptable credit risks. At times, such risks may be concentrated with certain counterparties or groups of counterparties. The credit worthiness of these counterparties is subject to continuing review.

## (8) COMMITMENTS AND CONTINGENCIES

The Company is involved in various legal actions and claims arising in the ordinary course of business. In the opinion of management, such litigation and claims are likely to be resolved without material adverse effect on the Company's financial position or results of operations.

In May 1998, a Domain stockholder filed an action in the Delaware Court of Chancery, alleging that the terms of the merger were unfair to a purported class of Domain stockholders and that the defendants (except Range) violated their legal duties to the class in connection with the Merger. Range is alleged to have aided and abetted the breaches of fiduciary duty allegedly committed by the other defendants. The action sought an injunction enjoining the Merger as well as a claim for monetary damages. In September 1998, the parties executed a Memorandum of Understanding (the "MOU"), which represented a settlement in principle. Under the terms of the MOU, appraisal rights (subject to certain conditions) were offered to all holders of Domain common stock (excluding the defendants and their affiliates). Domain agreed to pay court-awarded fees and expenses of plaintiffs' counsel in an amount not to exceed $300,000. The settlement was subject to court approval and certain other conditions which appear unlikely to be satisfied.

In February 2000, a royalty owner filed a suit asking for a class action certification against Great Lakes and the Company in the New York Supreme Court, alleging that gas was sold to affiliates and gas marketers at low prices, inappropriate post production expenses reduced proceeds to the royalty owners, and that Great Lakes improperly accounted for the royalty owners' share of gas. The action sought a proper accounting for all gas sold, an amount equal to the difference in prices paid and the highest obtainable prices, punitive damages and attorneys' fees. The case has been remanded to state court in New York. While the outcome of this suit is uncertain, the Company believes it will be resolved without material adverse effect on its financial position or results of operations.

The Company leases certain office space and equipment under cancelable and non-cancelable leases, most of which expire within three years and may be renewed by the Company. Rent expense under such arrangements totaled $0.6 million, $1.1 million and $1.0 million in 1998, 1999 and 2000, respectively. Future minimum rental commitments under non-cancelable leases are as follows (in thousands):

| | |
|---|---|
| 2001 | $ 857 |
| 2002 | 788 |
| 2003 | 515 |
| 2004 | 499 |
| 2005 | 499 |
| 2006 and thereafter | 124 |
| | $3,282 |

## (9) STOCKHOLDERS' EQUITY

In 1995, the Company issued 1,150,000 shares of $2.03 Convertible Exchangeable Preferred Stock Series C, (the "$2.03 Preferred") for $28.8 million. The $2.03 Preferred is convertible into 2.632 shares of common stock representing a conversion price of $9.50 per common share, subject to adjustment in certain events. The $2.03 Preferred is currently redeemable at the option of the Company, at a price of $25.75 per share, declining $0.25 each November 1st through 2003. At the option of the Company, the $2.03 Preferred is exchangeable for 8.125% Convertible Subordinated Notes subject to the same redemption and conversion terms as the $2.03 Preferred.

In September 2000, the Company authorized a $2.03 Convertible Exchangeable Preferred Stock Series D, having terms substantially identical to the outstanding Series C Preferred, with the exception that dividends could be paid in common stock. The option to pay dividends in common stock would expire on January 1, 2002. Dividends to be paid with common stock would be determined by dividing the amount of the dividend by the average closing price of the common stock on the three trading days prior to the dividend payment date, multiplied by 1.05. In November 2000, 523,140 shares of Series C were exchanged for Series D on a one-for-one basis. The shares of Series D issued in such exchanges were exempt from registration under Section 3(a)(9) of The Securities Act of 1933. In December 2000, 323,140 shares of Series D were exchanged for common stock. Subsequent to December 31, 2000, all remaining shares of Series D and all but 8,235 shares of Series C were exchanged for common stock. Annual cash dividend requirements on the remaining Series C Preferred amount to less than $17,000. During the year ended December 31, 2000, $23.2 million of the $2.03 Preferred was retired for 4.6 million shares of common stock. In January 2001, $5.3 million of the $2.03 Preferred was retired for 747,176 shares of common stock. No gains on the exchange of $2.03 Preferred are included in net income since the $2.03 Preferred is an equity security; however, the gains on such exchanges are included in income available to common shareholders. See Note 14.

In May 2000, shareholders approved an increase in the number of authorized shares of common stock from 50 million to 100 million.

*Supplemental disclosures of non-cash investing and financing activities*

| | Year Ended December 31, | | |
|---|---|---|---|
| | **1998** | **1999** | **2000** |
| | | **(in thousands)** | |
| Purchase of property and equipment financed with common stock | $116,469 | $ — | $ — |
| Common stock issued in connection with benefit plans | $ 1,887 | $1,783 | $ 816 |
| Common stock exchanged for convertible securities | $ — | $2,978 | $37,086 |
| Common stock issued in payment of preferred dividends | $ — | $ — | $ 110 |

## (10) STOCK OPTION AND PURCHASE PLANS

The Company has four stock option plans (two of which are currently active) and a stock purchase plan. Under these plans, incentive and non-qualified options and stock purchase rights are issued to directors, officers, and employees pursuant to decisions of the Compensation Committee of the Board. Information with respect to the stock option plans is summarized below:

| | **1999 Option Plan** | **1989 Option Plan** | **Directors' Option Plan** | **Domain Option Plan** | **Total** |
|---|---|---|---|---|---|
| Outstanding at December 31, 1999 | 60,000 | 2,496,482 | 168,000 | 563,267 | 3,287,749 |
| Granted | 643,200 | — | 56,000 | — | 699,200 |
| Exercised | — | (246,575) | (8,000) | (98,697) | (353,272) |
| Expired/canceled | (38,000) | (1,067,014) | (80,000) | (215,605) | (1,400,619) |
| Outstanding at December 31, 2000 | 665,200 | 1,182,893 | 136,000 | 248,965 | 2,233,058 |

In May 1999, Shareholders approved the 1999 Stock Incentive Plan (the "1999 Option Plan") providing for the issuance of options on up to 1.4 million shares of common stock. All options issued under the 1999 Option Plan vest 25% per year beginning one year after grant and expire in 10 years. During the year ended December 31, 2000, 643,200 options were granted under the 1999 Option Plan at exercise prices ranging from $1.94 to $4.69. Prior to those grants, 60,000 options were outstanding at a price of $5.63. On January 29, 2001, the Company granted 110,000 options at an exercise price of $6.40 per share. On February 13, 2001, the Company granted 624,350 options at an exercise price of $6.67 per share.

The Company also maintains the 1989 Stock Option Plan (the “1989 Option Plan”) which authorized the issuance of options on up to 3.0 million shares of common stock. No options have been granted under this plan since the adoption of the 1999 Option Plan. All options issued under the 1989 Option Plan vest 30% after one year, 60% after two years and 100% after three years and expire in 5 years. At December 31, 2000, 1.2 million options are outstanding under the 1989 Option Plan at exercise prices ranging from $2.63 to $18.00.

In 1994, Shareholders approved the 1994 Outside Directors’ Stock Option Plan (the “Directors’ Option Plan”) in which only non-employee directors may participate. In May 2000, Shareholders approved an increase in the number of options which could be issued under this Plan to 300,000 shares, extended the term of the options to ten years and extended the vesting period to four years. A total of 136,000 options are outstanding under the Plan at exercise prices ranging from $2.81 to $16.88.

In the Domain acquisition, the Domain stock option plan was adopted. Since that time, no options have been granted under the Plan and existing options became exercisable into Range common stock. A total of 248,965 options are outstanding under the Plan at prices ranging from $0.01 to $3.46.

In total, 2.2 million options are outstanding at December 31, 2000 at exercise prices ranging from $0.01 to $18.00 as follows:

*

| Exercise price | Average Exercise price | 1999 Option Plan | 1989 Option Plan | Directors’ Option Plan | Domain Option Plan | Total |
|---|---|---|---|---|---|---|
| $ 0.00 - $ 4.99 | $ 2.37 | 605,200 | 450,425 | 64,000 | 248,965 | 1,368,590 |
| 5.00 - 9.99 | 7.21 | 60,000 | 230,438 | — | — | 290,438 |
| 10.00 - 14.99 | 10.96 | — | 165,640 | 48,000 | — | 213,640 |
| 15.00 - 18.00 | 17.31 | — | 336,390 | 24,000 | — | 360,390 |
| Outstanding at December 31, 2000 | | 665,200 | 1,182,893 | 136,000 | 248,965 | 2,233,058 |

In 1997, Shareholders approved the 1997 Stock Purchase Plan (the “Stock Purchase Plan”) authorizing the sale of up to 900,000 shares of common stock to officers, directors, key employees and consultants. Under the Stock Purchase Plan, the right to purchase shares at prices ranging from 50% to 85% of market value may be granted. Through December 31, 2000, all purchase rights have been granted at 75% of market value. In May 2000, Shareholders approved an increase in the number of shares authorized for issuance under the Plan to 1,250,000. From inception through December 31, 2000, a total of 858,319 shares have been sold through the stock purchase plan, for a total consideration of $3.6 million. At December 31, 2000, remaining shares available for grant or purchase amounted to 391,681 shares.

The Company has adopted the disclosure-only provisions of SFAS No. 123, “Accounting for Stock-Based Compensation.” Accordingly, no compensation cost has been recognized for the stock option plans. Had compensation cost been determined based on the fair value at the grant date for awards in 1998, 1999 and 2000 consistent with the provisions of SFAS No. 123, the Company’s net income and earnings per share would have been reduced to the pro forma amounts indicated below:

| | Year Ended December 31, | | |
|---|---|---|---|
| | **1998** | **1999** | **2000** |
| | **(in thousands, except per share data)** | | |
| As reported - | | | |
| Net earnings (loss) | $(175,150) | $(7,793) | $37,961 |
| Earnings (loss) per share, basic and diluted | (6.82) | (0.27) | 0.99 |
| Pro forma - | | | |
| Net earnings (loss) | (176,569) | (8,858) | $37,796 |
| Earnings (loss) per share, basic and diluted | (6.88) | (0.30) | 0.99 |

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for 1998, 1999 and 2000, respectively: fair value of $1.24, $1.37 and $2.14 per share; dividend yields of $0.12, $0.03 and $0 per share; expected volatility factors of .79, 3.55 and 64.89; risk-free interest rates of 4.75%, 5.10% and 5.51%, and an average expected life of 6 years.

## (11) BENEFIT PLAN

The Company maintains a 401(k) Plan for the benefit of employees. The Plan permits employees to contribute up to 15% of their salary on a pre-tax basis. The Company makes discretionary contributions to the 401(k) Plan annually. In 1998, 1999 and 2000, the Company contributed $700,000, $854,000 and $483,000 of common stock (valued at market) to the 401(k) Plan.

## (12) INCOME TAXES

The Company’s federal income tax provision (benefit) for the years ended December 31, 1998, 1999 and 2000 was $(54.7) million, $0 million and $0 million, respectively. The current portion of income tax provision for 1999 represents state income tax currently payable. A reconciliation between the statutory federal income tax rate and the Company’s effective federal income tax rate is as follows:

| | **1998** | **1999** | **2000** |
|---|---|---|---|
| Statutory tax rate | (34)% | (34)% | 34% |
| Gain on retirement of securities | — | — | 32 |
| Permanent differences | — | — | 11 |
| Valuation allowance | 10 | 34 | (84) |
| State | — | — | (6) |
| Other | — | 19 | 5 |
| Effective tax rate | (24)% | 19% | (8)% |
| Income taxes paid | $36,000 | $388,000 | $ — |

The Company follows SFAS Statement No. 109, “Accounting for Income Taxes,” pursuant to which the liability method is used in accounting for taxes. Under this method, deferred tax assets and liabilities are determined based on differences between financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and regulations that will be in effect when the differences are expected to reverse.

Significant components of the Company's deferred tax liabilities and assets are as follows (in thousands):

| | December 31 | |
|---|---|---|
| | 1999 | 2000 |
| Deferred tax liabilities | | |
| Depreciation | $ 25,406 | $ 62,249 |
| Deferred tax assets | | |
| Net operating loss carryover | $ 47,433 | $ 66,870 |
| Percentage depletion carryover | 3,126 | 4,895 |
| AMT credits and other | 660 | 660 |
| Total deferred tax assets | 51,219 | 72,425 |
| Valuation allowance for deferred tax assets | (25,813) | (10,176) |
| Net deferred tax assets | $ 25,406 | $ 62,249 |
| Net deferred tax liabilities | $ — | $ — |

Utilization of the valuation allowance for the deferred tax asset of $10.2 million is dependent on future taxable profits being in excess of profits arising from existing taxable temporary differences. The Company has established a $10.2 million valuation allowance and has written down to zero its net deferred tax assets at December 31, 2000. Management believes sufficient uncertainty exists regarding its net deferred tax assets that a valuation allowance is required. Upon future realization of the deferred tax asset, $10.2 million of the valuation allowance will reduce the Company's future income tax expense.

The Company experienced a change of control in 1988 as defined by the Internal Revenue Code. As a result of this event and the Domain acquisition, there are limitations on the Company's ability to utilize certain net operating loss carryovers. At December 31, 2000, the Company had regular net operating loss carryovers of $191 million and alternative minimum tax ("AMT") net operating loss ("NOLs") carryovers of $171 million that expire between 2000 and 2020. In general terms, NOLs generated in prechange of control years can be utilized up to $10.6 million per year, while NOLs generated post change of control are not limited. The Company also has a statutory depletion carryover of $5.6 million and an AMT credit carryover of $660,000 which are not subject to limitations or expiration. The following table sets forth the year of expiration and amounts for the NOL carryovers:

| | NOL Carryover Amount | |
|---|---|---|
| Expiration | Regular | AMT |
| | (in thousands) | |
| 2001 | $ 1,180 | $ 1,180 |
| 2002 | 558 | 480 |
| 2003 | 488 | 422 |
| 2004 | 666 | 136 |
| Thereafter | 188,166 | 169,255 |
| Total | $191,058 | $171,473 |

### (13) RESTRUCTURING COSTS

In late 1998, the Company initiated a restructuring plan to reduce costs. The restructuring plan included closing the Midland, Texas field office, eliminating certain geological and exploration positions, canceling certain exploration and drilling obligations and consolidating administrative functions at the remaining locations. In connection with the restructuring, 54 employees were terminated. Estimated employee termination costs of $2.1 million were accrued in 1998. Of the employees affected, 42 were terminated in 1998 and 12 in 1999. In addition, the principal costs of the restructuring plan include the writedown of the carrying value of assets impaired due to the restructuring and lease and contract termination costs. The charge included $600,000 for estimated costs to cancel lease and other commitments and $400,000 associated with closing the Midland office. The $400,000 consisted of $100,000 to cancel the office lease and $300,000 to cancel two exploration agreements. At December 31, 1998, $2.7 million was accrued in connection with the restructuring plan. The plan was completed during 1999.

### (14) EARNINGS PER COMMON SHARE

The following table sets forth the computation of basic and diluted earnings per common share (in thousands except per share amounts):

| | Years Ended December 31, | | |
|---|---|---|---|
| | **1998** | **1999** | **2000** |
| Numerator: | | | |
| Income (loss) before extraordinary item | $(175,150) | $(10,223) | $20,198 |
| Gain on retirement of $2.03 Preferred Stock | — | — | 5,966 |
| Preferred dividends | (2,334) | (2,334) | (1,554) |
| Numerator for earnings (loss) per share, before extraordinary item | (177,484) | (12,557) | 24,610 |
| Extraordinary item | | | |
| Gain on retirement of securities | — | 2,430 | 17,763 |
| Numerator for earnings (loss) per share, basic and diluted | $(177,484) | $(10,127) | $42,373 |
| Denominator: | | | |
| Weighted average shares, basic | 26,008 | 36,933 | 42,882 |
| Dilutive potential common shares | | | |
| Employee stock options | — | — | 115 |
| Denominator for diluted earnings per share | 26,008 | 36,933 | 42,997 |
| Earnings (loss) per share, before extraordinary item — basic and diluted | $ (6.82) | $ (0.34) | $ 0.57 |
| Earnings (loss) per share — basic and diluted | $ (6.82) | $ (0.27) | $ 0.99 |

During 1998, 1999 and 2000, 718,279, 504,643 and 357,730 stock options were included in the computation of diluted earnings per share. All remaining stock options, the 6% Debentures, Trust Preferred and the $2.03 Preferred were not included in the computation because their inclusion would have been antidilutive.

The Company has and will continue to consider exchanging common stock or other equity-linked securities for certain of its fixed income securities. Existing common stockholders may be materially diluted if substantial exchanges are consummated. The extent of dilution will depend on the number of shares and price at which common stock is issued, the price at which newly issued securities are convertible into common stock, and the price at which fixed income securities are reacquired.

### (15) MAJOR CUSTOMERS

The Company markets its production on a competitive basis. Gas is sold under various types of contracts ranging from life-of-the-well to short-term contracts that are cancelable within 30 days. Prior to hedging, virtually all of the Company's gas production is currently sold under market sensitive contracts. Oil purchasers may be changed on 30 days notice. The price received is generally equal to a posted price set by major purchasers in the area. The Company sells to oil purchasers on the basis of price and service. For the year ended December 31, 2000, three customers accounted for 10% or more of total oil and gas revenues. Management believes that the loss of any one customer would not have a material adverse effect on the Company.

Great Lakes sells 90% of its gas production to FirstEnergy, at prices based on the close of NYMEX each month plus a basis differential. While Great Lakes may sell gas to third parties, such arrangements must be contracted through FirstEnergy and FirstEnergy has the right to match any such arrangements. In September 2000, the parties amended the base contract to have its term automatically renewed for one-month periods through June 30, 2001. The amendments identified gas marketing services to be performed by FirstEnergy and defined the service fees to be paid by Great Lakes. Additionally, terms and conditions of the gas purchase agreement were further defined, including pricing, delivery points and projected volumes.

### (16) OIL AND GAS ACTIVITIES

The following summarizes selected information with respect to oil and gas producing activities:

| | Year Ended December 31, | | |
|---|---|---|---|
| | **1998** | **1999** | **2000** |
| | | **(in thousands)** | |
| Oil and gas properties: | | | |
| Subject to depletion | $ 859,911 | $ 914,173 | $ 965,416 |
| Unproved | 75,911 | 61,812 | 49,523 |
| Total | 935,822 | 975,985 | 1,014,939 |
| Accumulated depletion | (273,723) | (383,622) | (443,097) |
| Net oil and gas properties | $ 662,099 | $ 592,363 | $ 571,842 |
| Costs incurred: | | | |
| Acquisition | $ 286,974 | $ 846 | $ 4,701 |
| Development | 71,793 | 33,808 | 49,006 |
| Exploration | 9,756 | 3,604 | 4,498 |
| Total costs incurred | $ 368,523 | $ 38,258 | $ 58,205 |

Acquisition costs in 1999 do not reflect $68 million of value associated with the Company receiving a 50% interest in the reserves contributed by FirstEnergy to Great Lakes. The Company's share of such reserves was 81.6 Bcfe. Exploration costs include capitalized as well as expensed outlays.

## (17) INVESTMENT IN GREAT LAKES

As described in Note 2, the Company owns 50% of Great Lakes and consolidates its proportionate interest in Great Lakes' assets, liabilities, revenues and expenses. The following table summarizes the Company's interest in selected financial data from Great Lakes' audited financial statements at or for the periods ended December 31, 1999 and 2000.

| | December 31, | |
|---|---|---|
| | 1999 | 2000 |
| | (In thousands) | |
| Current assets | $ 10,073 | $ 6,568 |
| Oil and gas properties, net | 144,981 | 146,992 |
| Transportation and field assets, net | 19,389 | 17,557 |
| Other assets | 1,033 | 691 |
| liabilities | 6,101 | 8,332 |
| Long-term debt | 95,020 | 84,509 |
| Members' equity | 74,355 | 78,967 |
| Revenues | 9,586 | 39,732 |
| Net income | 1,821 | 8,353 |

(a) Great Lakes commenced operations on October 1, 1999.

## (18) GAIN ON FORMATION OF GREAT LAKES

In September 1999, Range transferred all of its Appalachian oil and gas properties and associated gas gathering and transportation systems to Great Lakes in exchange for a 50% ownership interest. Additionally, the Company contributed $188.3 million of indebtedness to Great Lakes. The Great Lakes partners have no commitment to support the operations or obligations of Great Lakes. In connection with the transfer, Range recognized a gain of $39.8 million, which was attributable to the portion of the net assets conveyed to Great Lakes. The gain was calculated by comparing the Company's estimate of the fair market value of the assets and liabilities conveyed to their net book value.

## (19) EXTRAORDINARY ITEM

During 1999, 699,000 shares of common stock were exchanged for $2.3 million of Trust Preferred and $3.6 million of 6% Debentures. During 2000, 5.7 million shares of common stock were exchanged for $25.0 million of Trust Preferred and $13.8 million of 6% Debentures. In connection with these exchanges, an extraordinary gain net of costs of $2.4 million and $17.8 million was recorded in 1999 and 2000, respectively, because the Trust Preferred and 6% Debentures were retired at a discount. In addition, 4.6 million shares of common stock were exchanged for $23.2 million of the $2.03 Preferred during 2000.

## (20) UNAUDITED SUPPLEMENTAL RESERVES INFORMATION

The Company's proved oil and gas reserves are located in the United States. Proved reserves are those quantities of crude oil and natural gas which, upon analysis of geological and engineering data, can with reasonable certainty be recovered in the future from known oil and gas reservoirs. Proved developed reserves are those proved reserves, which can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage.

**Quantities of Proved Reserves**

| | Crude Oil (Mbbls) | Natural Gas (Mmcf) | Natural Gas Equivalent (Mmcfe) |
|---|---|---|---|
| Balance, December 31, 1997 | 29,774 | 574,418 | 753,062 |
| Revisions | (14,195) | (76,728) | (161,898) |
| Extensions, discoveries and additions | 2,121 | 57,261 | 69,987 |
| Purchases | 15,332 | 140,120 | 232,112 |
| Sales | (3,248) | (16,561) | (36,049) |
| Production | (2,655) | (45,193) | (61,123) |
| Balance, December 31, 1998 | 27,129 | 633,317 | 796,091 |
| Revisions | 1,294 | (39,298) | (31,534) |
| Extensions, discoveries and additions | 307 | 11,066 | 12,908 |
| Purchases | 5,241 | 51,751 | 83,197 |
| Sales | (2,495) | (162,245) | (177,215) |
| Production | (2,659) | (50,808) | (66,762) |
| Balance, December 31, 1999 | 28,817 | 443,783 | 616,685 |
| Revisions | (1,699) | (1,186) | (11,380) |
| Extensions, discoveries and additions | 1,226 | 26,639 | 33,996 |
| Purchases | 226 | 1,605 | 2,962 |
| Sales | (170) | (2,135) | (3,155) |
| Production | (2,398) | (41,039) | (55,428) |
| Balance, December 31, 2000 | 26,002 | 427,667 | 583,680 |
| **Proved developed reserves** | | | |
| December 31, 1998 | 19,649 | 436,062 | 553,956 |
| December 31, 1999 | 17,884 | 299,436 | 406,740 |
| December 31, 2000 | 17,215 | 305,796 | 409,086 |

Between late 1997 and mid-1998, a series of large acquisitions were consummated which proved extremely disappointing. Production from the acquired properties fell more rapidly than anticipated and further development results were far less attractive than projected in the acquisition engineering. The steep decline in energy prices, which began in late 1997, combined with the less than expected performance caused certain downward reserve revisions in 1998. In 1999, a series of exhaustive field performance studies were conducted and the properties were re-engineered. The studies included a complete review of 1997 and 1998 capital expenditures and development results, a re-examination of estimates of reservoir thickness, oil and gas in place, ultimate recoverable reserves and the relationship of pressures and production declines to these estimates. Reserve reductions were recorded in 1999, based primarily on performance and a reassessment of the size of the reservoirs offset to a minor degree by upward revisions due to price increases. The 1999 development program in these fields was in part designed to confirm revised engineering forecasts. The downward revisions at year-end 2000 represented what is believed to be the final integration of the field studies, 1999 and 2000 development results, pressure data and production declines. Adjustments at year-end 2000 involved removing from proved reserves drilling and recompletion locations that, based on perceived risk, will probably not be drilled. While there can be no assurance that future reserve revisions will not occur, management believes that it has fully assessed all data available through this date. That assumption is supported by the fact that performance in the fields appears to have finally stabilized.

The average prices used at December 31, 2000 to estimate the reserve information were $24.46 per barrel for oil, $14.91 per barrel for natural gas liquids and $9.57 per Mcf for gas using the benchmark NYMEX prices of $26.80 per barrel and $9.77 per Mmbtu. The average prices at December 31, 1999 were $23.48 per barrel for oil, $15.69 per barrel for natural gas liquids and $2.34 per Mcf for gas using the benchmark NYMEX prices of $25.60 per barrel and $2.44 per Mmbtu.

The “Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves” (“Standardized Measure”) is a disclosure requirement of SFAS No. 69, “Disclosures about Oil and Gas Producing Activities.” The Standardized Measure does not purport to present the fair market value of proved oil and gas reserves. This would require consideration of expected future economic and operating conditions, which are not taken into account in calculating the Standardized Measure.

Future cash inflows were estimated by applying year end prices to the estimated future production less estimated future production costs based on year end costs. Future net cash inflows were discounted using a 10% annual discount rate to arrive at the Standardized Measure.

**Standardized Measure**

| | As of December 31, | | |
|---|---|---|---|
| | **1998** | **1999** | **2000** |
| | | **(in thousands)** | |
| Future cash inflows | $1,744,653 | $1,689,541 | $ 4,697,062 |
| Future costs: | | | |
| Production | (513,119) | (486,618) | (755,727) |
| Development | (211,236) | (189,784) | (177,070) |
| Future net cash flows | 1,020,298 | 1,013,139 | 3,764,265 |
| Income taxes | (104,500) | (131,529) | (457,996) |
| Total undiscounted future net cash flows | 915,798 | 881,610 | 3,306,269 |
| 10% discount factor | (398,703) | (378,459) | (1,800,007) |
| Standardized measure | $ 517,095 | $ 503,151 | $ 1,506,262 |

### Changes in Standardized Measure

| | As of December 31, | | |
|---|---|---|---|
| | 1998 | 1999 | 2000 |
| | | (in thousands | |
| Standardized measure, beginning of year | $ 510,700 | $ 517,095 | $ 503,151 |
| Revisions: | | | |
| Prices | (138,985) | 128,799 | 1,184,950 |
| Quantities | (112,012) | (37,911) | (89,180) |
| Estimated future development cost | 26,465 | 8,941 | 36,650 |
| Accretion of discount | 63,233 | 45,420 | 63,468 |
| Income taxes | 88,222 | (14,307) | (130,626) |
| Net revisions | (73,077) | 130,942 | 1,065,262 |
| Purchases | 134,186 | 71,022 | 8,003 |
| Extensions, discoveries and additions | 35,169 | 16,354 | 91,855 |
| Production | (87,668) | (77,884) | (134,556) |
| Sales | (26,197) | (136,491) | (8,525) |
| Changes in timing and other | 23,982 | (17,887) | (18,928) |
| Standardized measure, end of year | $ 517,095 | $ 503,151 | $1,506,262 |

## RANGE RESOURCES CORPORATION

## INDEX TO EXHIBITS

## (Item 14[a 3])

| Exhibit No. | Description |
|---|---|
| 3.1.1. | Certificate of Incorporation of Lomak dated March 24, 1980 (incorporated by reference to the Company's Registration Statement (No. 33-31558)). |
| 3.1.2. | Certificate of Amendment of Certificate of Incorporation dated July 22, 1981 (incorporated by reference to the Company's Registration Statement (No. 33-31558)). |
| 3.1.3. | Certificate of Amendment of Certificate of Incorporation dated September 8, 1982 (incorporated by reference to the Company's Registration Statement (No. 33-31558)). |
| 3.1.4. | Certificate of Amendment of Certificate of Incorporation dated December 28, 1988 (incorporated by reference to the Company's Registration Statement (No. 33-31558)). |
| 3.1.5. | Certificate of Amendment of Certificate of Incorporation dated August 31, 1989 (incorporated by reference to the Company's Registration Statement (No. 33-31558)). |
| 3.1.6. | Certificate of Amendment of Certificate of Incorporation dated May 30, 1991 (incorporated by reference to the Company's Registration Statement (No. 333-20259)). |
| 3.1.7. | Certificate of Amendment of Certificate of Incorporation dated November 20, 1992 (incorporated by reference to the Company's Registration Statement (No.-333-20257)). |
| 3.1.8. | Certificate of Amendment of Certificate of Incorporation dated May 24, 1996 (incorporated by reference to the Company's Registration Statement (No.333-20257)). |
| 3.1.9. | Certificate of Amendment of Certificate of Incorporation dated October 2, 1996 (incorporated by reference to the Company's Registration Statement (No. 333-20257)). |
| 3.1.10. | Restated Certificate of Incorporation as required by Item 102 of Regulation S-T (incorporated by reference to the Company's Registration Statement (No. 333-20257)). |
| 3.1.11. | Certificate of Amendment of Certificate of Incorporation dated August 25, 1998 (incorporated by reference to the Company's Registration Statement (No. 333-62439)). |
| 3.1.12 | Certificate of Amendment of Certificate of Incorporation dated May 25, 2000 (incorporated by reference to the Company's Form 10-Q dated August 8, 2000). |
| 3.2 | By-Laws of the Company (incorporated by reference to the Company's Registration Statement (No. 33-31558)). |
| 4.1 | Specimen certificate of Lomak Petroleum, Inc. (incorporated by reference to the Company's Registration Statement (No. 333-20257)). |
| 4.2 | Certificate of Trust of Lomak Financing Trust (incorporated by reference to the Company's Registration Statement (No. 333-43823)). |
| 4.3 | Amended and Restated Declaration of Trust of Lomak Financing Trust dated as of October 22, 1997 by The Bank of New York (Delaware) and the Bank of New York as Trustees and Lomak Petroleum, Inc. as Sponsor (incorporated by reference to the Company's Registration Statement (No. 333-43823)). |
| 4.4.1 | Indenture dated as of October 22, 1997, between Lomak Petroleum, Inc. and The Bank of New York (incorporated by reference to the Company's Registration Statement (No. 333-43823)). |

| Exhibit No. | Description |
|---|---|
| 4.4.2 | First Supplemental Indenture dated as of October 22, 1997, between Lomak Petroleum, Inc. and The Bank of New York (incorporated by reference to the Company’s Registration Statement (No. 333-43823)). |
| 4.5 | Form of 5 3/4% Preferred Convertible Securities (included in Exhibit 4.3 above). |
| 4.6 | Form of 5 3/4% Convertible Junior Subordinated Debentures (included in Exhibit 4.4.2 above). |
| 4.7 | Convertible Preferred Securities Guarantee Agreement dated October 22, 1997, between Lomak Petroleum, Inc., as Guarantor, and The Bank of New York as Preferred Guarantee Trustee (incorporated by reference to the Company’s Registration Statement (No. 333-43823)). |
| 4.8 | Common Securities Guarantee Agreement dated October 22, 1997, between Lomak Petroleum, Inc., as Guarantor, and The Bank of New York as Common Guarantee Trustee. (incorporated by reference to the Company’s Registration Statement No. 333-43823)). |
| 4.9 | Form of Trust Indenture relating to the Senior Subordinated Notes due 2007 between Lomak Petroleum, Inc., and Fleet National Bank as trustee (incorporated on the Company’ s Registration Statement (No. 333-20257)). |
| 4.10 | Credit Agreement, dated as of June 7, 1996, between Domain Finance Corporation and Compass Bank — Houston (including the First and the Second Amendment thereto) (incorporated by reference to Exhibit 10.3 of Domain Energy Corporation's Registration Statement on Form S-1 filed with the Commission on April 4, 1997 and Exhibit 10.3 of Amendment No. 1 to Domain Energy Corporation's Registration Statement on Form S-1 filed with the Commission on May 21, 1997) (File No. 333-24641). |
| 4.11 | Corrected Certificate of Designations of Preferred Stock of Range Resources Corporation Designated As $2.03 Convertible Exchangeable Preferred Stock, Series D (incorporated by reference to the Company's Form 10-Q dated November 6, 2000). |
| 10.1 | Incentive and Non-Qualified Stock Option Plan dated March 13, 1989 (incorporated by reference to the Company's Registration Statement (No. 33-31558)). |
| 10.2.1 | 1989 Stock Option Plan (incorporated by reference to the Company's Registration Statement (No. 33-31558)). |
| 10.2.2 | Amendment to the Lomak Petroleum, Inc., 1989 Stock Option Plan, as amended (incorporated by reference to the Company's Registration Statement (No. 333-44821)). |
| 10.3 | Form of Directors Indemnification Agreement (incorporated by reference to the Company's Registration Statement (No. 333-47544)). |
| 10.4.1 | 1994 Outside Directors Stock Option Plan (incorporated by reference to the Company's Registration Statement (No. 33-47544)). |
| 10.4.2 | 1994 Outside Directors Stock Option Plan — Amendment No. 1 (incorporated by reference to the Company's Registration Statement No. 333-40380) |
| 10.4.3 | 1994 Outside Directors Stock Option Plan — Amendment No. 2 (incorporated by reference to the Company's Registration Statement No. 333-40380) |
| 10.4.4 | 1994 Outside Directors Stock Option Plan — Amendment No. 3 (incorporated by reference to the Company's Registration Statement No. 333-40380) |
| 10.4.5 | 1994 Outside Directors Stock Option Plan — Amendment No. 4 (incorporated by reference to the Company's Registration Statement No. 333-40380) |
| 10.5 | 1994 Stock Option Plan (incorporated by reference to the Company's Registration Statement (No. 33-47544)). |
| 10.6 | Registration Rights Agreement dated October 22, 1997, by and among Lomak Petroleum, Inc., Lomak Financing Trust, Morgan Stanley & Co. Incorporated, Credit Suisse First Boston, Forum Capital markets L.P. and McDonald Company Securities, Inc., (incorporated by reference to the Company's Registration Statement (No. 333-43823)). |

| Exhibit No. | Description |
|---|---|
| 10.7.1 | 1997 Stock Purchase Plan (incorporated by reference to the Company’s Registration Statement (No. 333-44821)). |
| 10.7.2 | 1997 Stock Purchase Plan, as amended (incorporated by reference to the Company’s Registration Statement (No. 333-44821)). |
| 10.7.3 | 1997 Stock Purchase Plan — Amendment No. 1 (incorporated by reference to the Company's Registration Statement No. 333-40380) |
| 10.7.4 | 1997 Stock Purchase Plan — Amendment No. 2 (incorporated by reference to the Company's Registration Statement No. 333-40380) |
| 10.7.5 | 1997 Stock Purchase Plan — Amendment No. 3 (incorporated by reference to the Company's Registration Statement No. 333-40380) |
| 10.8 | Second Amended and Restated 1996 Stock Purchase and Option Plan for Key Employees of Domain Energy Corporation and Affiliates (incorporated by reference to the Company's Registration Statement (No. 333-62439)). |
| 10.9 | Domain Energy Corporation 1997 Stock Option Plan for Nonemployee Directors (incorporated by reference to the Company's Registration Statement (No. 333-62439)). |
| 10.10 | $100,000,000 Credit Agreement between Range Energy Finance Corporation, as Borrower, and Credit Lyonnais New York Branch, as Administrative Agent and Certain Lenders dated December 14, 1999 (incorporated by reference to the Company's 1999 10K dated March 20, 2000. |
| 10.11 | Purchase and Sale Agreement — Dated April 20, 2000 between Range Pipeline Systems, L.P. as Seller and Conoco Inc., as Buyer (incorporated by reference to the Company's 10-Q dated August 8, 2000). |
| 10.12 | Gas Purchase Contract — Dated July 1, 2000 between Range Production I, L.P. as Seller and Conoco Inc., as Buyer (incorporated by reference to the Company's 10-Q dated August 8, 2000). |
| 10.13 | Application Service Provider and Outsourcing Agreement É Dated June 1, 2000 between Range Resources and Applied Terravision Systems Inc. (incorporated by reference to the Company's 10-Q dated August 8, 2000). |
| 10.14.1 | $225,000,000 Amended and Restated Credit Agreement among Range Resources Corporation, as Borrower, The Lenders from Time to Time Parties Hereto, as Lenders, Bank One, Texas, N.A., as Administrative Agent, Chase Bank of Texas, N.A., as Syndication Agent, and Bank of America, N.A., as Documentation Agent dated September 30, 1999, incorporated by reference to the Company's 10Q dated November 10, 1999. |
| 10.14.2* | $225,000,000 First Amendment to Credit Agreement among Range Resources Corporation, as Borrower, certain parties, as Lenders, Bank One, Texas, N.A., as Administrative Agent, Chase Bank of Texas, N.A., as syndication Agent, and Bank of America, N.A., as Documentation Agent dated September 30, 1999 |
| 10.14.3 | $225,000,000 Second Amendment to Credit Agreement among Range Resources Corporation, as Borrower, certain parties, as Lenders, Bank One, Texas, N.A., as Administrative Agent, Chase Bank of Texas, N.A., as syndication Agent, and Bank of America, N.A., as Documentation Agent dated September 30, 1999 (incorporated by reference to the Company's 10-Q dated August 8, 2000 |
| 10.15* | The Amended and Restated Deferred Compensation Plan for Directors and Selected Employees, effective September 1, 2000. |
| 21* | Subsidiaries of Registrant. |
| 23.1* | Consent of Independent Public Accountants. |
| 23.2* | Consent of H.J. Gruy and Associates, Inc., independent consulting petroleum engineers. |
| 23.3* | Consent of DeGoyler and MacNaughton, independent consulting petroleum engineers. |
| 23.4* | Consent of Wright and Company, independent consulting engineers. |

* Filed herewith.