SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K/A

(MARK ONE)

{x} ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (FEE REQUIRED)
For the fiscal year ended December 31, 1998

{ } TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 (NO FEE REQUIRED)
For the transaction period from _______ to _______

COMMISSION FILE NUMBER 0-9592

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

DELAWARE (State of incorporation)	34-1312571 (I.R.S. Employer Identification No.)
500 THROCKMORTON STREET, FT. WORTH, TEXAS (Address of principal executive offices)	76102 (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. {X}

The aggregate market value of voting stock of the registrant held by non-affiliates (excluding voting shares held by officers and directors) was $87,329,093 on March 9, 1999.

Indicate the number of shares outstanding of each of the registrant's classes of stock on March 9, 1999: Common Stock $.01 par value: 36,273,196; Preferred Stock $1 par value: 1,149,840.

DOCUMENTS INCORPORATED BY REFERENCE:
Part III of this report incorporates by reference the Proxy Statement relating to the Registrant's 1999 Annual Meeting of Stockholders.

RANGE RESOURCES CORPORATION

ANNUAL REPORT ON FORM 10-K
YEAR ENDED DECEMBER 31, 1998

PART I

ITEM 1. BUSINESS

GENERAL

Range Resources Corporation ("Range" or the "Company") is an independent oil and gas company operating in the following core areas of operation: the Appalachian, Permian, Midcontinent and Gulf Coast regions. The Company seeks to build value through a balanced approach of low-risk development and acquisition, higher risk exploitation and exploration and producer financing. Through its Independent Producer Finance subsidiary, the Company engages in producer financing activities by purchasing term overriding royalties in oil and gas properties. In pursuing this strategy, the Company has concentrated its activities in selected geographic areas. In each core area, the Company has established operating, engineering, geoscience, marketing and acquisition expertise. At December 31, 1998, the Company had combined proved reserves totaling 796 Bcfe, having a pre-tax present value at constant prices on that date of $555 million. On an Mcfe basis, the reserves were 80% natural gas, are 80% operated by the Company and have a reserve life index in excess of 13 years.

In August 1998, the stockholders of Lomak Petroleum, Inc ("Lomak") approved the acquisition via merger (the "Merger") of Domain Energy Corporation ("Domain"). As a result of the Merger, Domain became a wholly-owned subsidiary of Lomak. Simultaneously, Lomak stockholders approved changing the Company's name to Range Resources Corporation.

DESCRIPTION OF THE BUSINESS

Strategy

The Company's objective is to maximize stockholder value through a balanced strategy that combines lower risk development and acquisition activities with higher risk, higher impact exploitation and exploration projects. Since 1990, total assets have grown from $24 million to $922 million at year end 1998. During this same period of time, stockholders' equity has increase from $6 million to $133 million. In 1999, the Company's goal is to reduce leverage and position the Company to benefit from, rather than merely endure, the downturn in commodity prices. The Company plans to reduce leverage by cutting costs, monetizing assets and limiting exploration and development capital expenditures to internal cash flow. These monetizations could include contributing oil and gas operations or assets and debt into a joint venture, selling net profits interests in oil and gas properties or selling interests in oil and gas properties through an oil and gas royalty trust. The proceeds from the monetization of oil and gas assets are expected to reduce outstanding amounts under the Credit Facility. The Company's goal is to reduce debt as a percentage of total capitalization to levels at or below 50% within 12 to 24 months. While it will be difficult to generate substantial production growth with a reduced 1999 capital budget, the cost reductions and monetization and sale of assets position Range to weather a prolonged downturn in commodity prices. When prices rebound, the Company should be in position to increase the rate of exploitation of its large development and exploration inventory.

Management believes that the acquisitions completed since 1990 have substantially enhanced the Company's ability to increase its production and reserves through the ongoing development of the acquired properties. The Company now has over 1,400 proven recompletions and development drilling wells. With its large development inventory, the Company believes that if oil and gas prices rebound it can achieve growth in reserves, production, cash flow and earnings over the next several years, without the benefit of future acquisitions. The Company currently anticipates spending approximately $35 million to $40 million during 1999 on development and exploration activities. The Company's leasehold position now totals approximately 1.9 million gross acres (1.2 million net), providing significant long-term development and exploration potential.

In order to effectively implement its operating strategy, the Company has concentrated its activities in selected geographic areas. In its core areas, the Company has established separate business units, each with operating, engineering, geological, land and acquisition expertise. The Company believes that this focus provides it with a competitive advantage in sourcing and evaluating new business opportunities, as well as providing economies of scale in operating and developing its properties. Management believes each business unit's facilities are adequate to meet the Company's current needs and existing facilities could be expanded.

Development. The Company's development activities include recompletions of existing wells, infill drilling and installation of secondary recovery projects. The Company's development wells are generated within core areas where the Company has significant operational and technical experience. At December 31, 1998, over 1,400 proven development wells were in inventory. In view of the low current oil and gas prices, the Company plans to limit its 1999 development expenditures to approximately $35 million. The Company expects development expenditures in the Appalachian, Gulf Coast and Southwest business units to approximate $9 million, $10 million and $16 million, respectively.

Exploration. Beginning in 1996, the Company began to conduct exploration activities on or near existing properties within its core operating areas. Range has domestic onshore exploration projects covering 536,000 gross acres. The Company's onshore exploration program targets deeper horizons within existing Company-operated fields, as well as establishing new fields in exploration trend areas in which Range's technical staff has experience. Range's offshore exploration program focuses on the shallow waters of the Gulf of Mexico where it holds contiguous 3D seismic data covering 3.5 million acres. Range has offshore leases covering 11,000 gross acres on which it has identified 80 projects. Range's strategy is based upon limiting its risk by allocating no more than 10% of its cash flow to exploration activities and by participating in a variety of projects with differing characteristics. In view of the low current oil and gas prices the Company anticipates exploratory expenditures to be less than $5 million in 1999. The Company expects exploration expenditures in the Appalachian, Gulf Coast and Southwest business units to approximate $.5 million, $3 million and $1.5 million, respectively.

Acquisitions. Since 1990, 70 acquisitions have been completed for a total consideration of $974 million. These acquisitions have been made at an average cost of $0.77 per Mcfe. The Company's acquisition strategy has historically been based on: (i) Locale: focusing in core areas where the Company has operating and technical expertise; (ii) Efficiency: targeting acquisitions in which operating and cost efficiencies can be obtained; (iii) Reserve Potential: pursuing properties with the potential for reserve increases through recompletions and drilling; (iv) Incremental Purchases: seeking acquisitions where opportunities for purchasing additional interests in the same or adjoining properties exist; and (v) Complexity: pursuing more complex but less competitive corporate acquisitions.

DEVELOPMENT AND EXPLORATION ACTIVITIES

During 1998, the Company spent $81.5 million on development and exploration activities versus $58.8 million in 1997. Of this total, $53 million was expended in the Southwest, $18 million in Appalachia and $10 million in the Gulf Coast. These expenditures funded 70 recompletions of existing wells, 234 new development wells and 14 exploratory wells, as well as leasehold and seismic acquisition. As a result of these activities, 70 Bcfe of proved reserves were added representing 115% of 1998 production.

Development Activities

The Company's development activities include recompletions of existing wells, infill drilling and to a lesser extent, installation of secondary recovery projects. Development wells are located within core operating areas where the Company has established operational and technical expertise. Currently, as described below, the Company has 1,493 proven development wells in inventory. Those wells are geographically diverse, target a mix of oil and gas and are generally less than 8,000 feet in depth. Approximately 74% of the development wells are concentrated in 21 fields covering 512,000 gross acres. Such large acreage blocks and concentration of wells provide economies of scale, access to competitively priced oil field services and focused operating and technical expertise. The following table sets forth information pertaining to the Company's proven development inventory at December 31, 1998.

	NUMBER OF PROJECTS		
	RECOMPLETION OPPORTUNITIES	DRILLING LOCATIONS	TOTAL
Southwest			
Permian	310	211	521
Midcontinent	44	33	77
Subtotal	354	244	598
Gulf Coast	110	44	154
Appalachia	2	739	741
Total	466	1,027	1,493

In addition, the Company has identified over 200 projects on its existing leasehold, which at December 31, 1998 were not classified as proven. A portion of these projects are included in each year's development program. These projects include field extension drilling and recompletions to formations not extensively under production.

Range completed 304 development projects in 1998, including drilling 234 wells and 70 recompletions. This level of activity was 13% higher than in 1997. The 1998 development expenditures of $71.8 million exceeded 1997 by 27%, reflecting increased activity and a higher average working interest. In the Southwest business unit, the Company spent $47 million to recomplete 51 wells and drill an additional 104 wells. Development activity in the Gulf Coast included the drilling of 6 wells and the recompletion of 7 others for $6 million. In Appalachia, $18 million was spent to drill 124 wells and recomplete 12 others.

Exploration Activities

Domestic Onshore Exploration. Range has onshore exploration projects covering 767,000 gross acres, including seven projects in the Southwest and fifteen in Appalachia. Each project has multiple drilling prospects, some with multiple targets. During 1998, the Company spent $4.7 million to acquire established acreage, shoot and process seismic data and drill 11 wells.

Gulf of Mexico Exploration. Via Domain, Range acquired a 3D seismic database covering 700 contiguous blocks in the shallow waters of the Gulf of Mexico, 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. To date, 80 prospects have been identified. These prospects target the Miocene formation at depths of 10,000 to 12,000 feet. Subsequent to the Merger, the Company participated in 3 gross, 1.2 net exploration wells, all of which were plugged and abandoned, at a cost of approximately $4.1 million.

ACQUISITION ACTIVITIES

In 1998, Range completed acquisitions for $224 million in consideration. The significant acquisitions are described below.

In March 1998, oil and gas properties in the Powell Ranch Field in West Texas (the "Powell Ranch Properties") were acquired for a purchase price of $60 million, comprised of $54.6 million in cash and $5.4 million of Common Stock.

In August 1998, the Company acquired Domain via merger for a purchase price of $161.6 million, comprised of $50.5 million in cash and $111.1 million of Common Stock. Domain's principal assets primarily included oil and gas operations onshore in the Gulf Coast and in the Gulf of Mexico, as well as the investment activities of IPF.

PRODUCTION

Production revenue is generated through the sale of oil, natural gas liquids and gas from properties owned directly and through partnerships and joint ventures. Additional revenue is received from royalties. While production is sold to a limited number of purchasers, only one accounts for more than 10% of oil and gas revenues. Management believes that the loss of any one customer would not have a material adverse effect on the business. Proximity to local markets, availability of competitive fuels and overall supply and demand are factors affecting the ability to market production. While the Company anticipates an upward trend in energy prices, factors outside its control such as political developments in the Middle East, overall energy supply, weather conditions and economic growth rates have had, and will continue to have, a significant effect on energy prices.

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

	Year Ended December 31,				
	1994	1995	1996	1997	1998
Production					
Oil and NGL (Bbl)	640	913	1,068	1,794	2,655
Gas (Mcf)	6,996	12,471	21,231	38,409	45,193
Total (Mcfe) (a)	10,836	17,949	27,641	49,170	61,120
Revenues					
Oil and NGL	$ 9,743	$ 15,133	$ 20,425	$ 28,800	$ 30,084
Gas	14,718	22,284	47,629	101,217	105,509
Total	$ 24,461	$ 37,417	$ 68,054	$130,017	$135,593
Average Sales Price					
Oil (Bbl)	$ 15.23	$ 16.57	$ 19.56	$ 18.22	$ 12.01
NGL (Bbl)	--	--	$ 10.22	$ 9.06	$ 8.26
Gas (Mcf)	$ 2.10	$ 1.79	$ 2.24	$ 2.64	$ 2.33
Mcfe (a)	$ 2.26	$ 2.08	$ 2.46	$ 2.64	$ 2.22
Average Operating Cost Per Mcfe (a)	$ 0.75	$ 0.63	$ 0.75	$ 0.64	$ 0.64

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

On a Mcfe basis, approximately 74% of 1998 production was natural gas. Gas production was sold to utilities, brokers or directly to industrial users. Gas sales are made pursuant to various arrangements ranging from month-to-month contracts, one year contracts at fixed or variable prices and contracts at 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. A number of the Appalachian gas contracts are at prices which compare favorably to the spot market. Oil is sold on a basis such that the purchaser can be changed on 30 days notice. The price received is generally equal to a posted price set by the major purchasers in the area. Oil purchasers are selected on the basis of price and service. In 1998, revenues from gas sales totaled $105.5 million or 78% of total oil and gas revenues while revenues from oil and natural gas liquids production amounted to $30.1 million, representing 22% 7of total oil and gas revenues. Oil and gas revenues for 1998 increased 4% over 1997.

GAS TRANSPORTATION, PROCESSING AND MARKETING

The gas transportation, processing and marketing revenues are comprised of fees for the transportation of production through gathering lines and fees from gas processing as well as, income from marketing of oil and gas. Transportation, processing and marketing revenues decreased 14% to $6.7 million versus $7.8 million in 1997. The decrease was principally due to the sale of a gas processing plant in the San Juan Basin and a drop in natural gas liquid prices which lowered gas processing revenue.

The Company's natural gas transportation and processing assets are primarily comprised of (i) approximately 2,700 miles of gas transportation and gathering pipelines in Appalachia and (ii) nearly 300 miles of gathering lines in the Sterling area of the Permian Basin. The Appalachian gas gathering systems serve to transport a majority of the Company's Appalachian gas production as well as third party gas to major trunklines and directly to industrial end-users. This affords the Company considerable control and flexibility in marketing its Appalachian production. Third parties who transport their gas through the systems are charged a gathering fee based on throughput. In its Permian, Midcontinent and Gulf Coast areas, the Company transports its gas production through a combination of Company-owned and third party gathering systems. The Company is typically charged a fixed fee per volume of production to transport its gas through third party systems. The Company's Sterling gas processing plant is a refrigerated turbo-expander cryogenic gas plant that was placed in service in early 1995. The plant, designed for approximately 25,000 Mcf/d, is currently operating at 74% of capacity. The Company estimates that the plant's capacity can be increased to 35,000 Mcf/d for approximately $4.0 million in additional capital expenditures.

In order to maximize the price it receives for the sale of natural gas, the Company began to market its own gas production in 1993. The Company's marketing efforts are primarily composed of its in-house sales force selling production directly to customers at the most favorable price. The Company is currently marketing 196 Mmcf/d for its own account as well as for third party producers. The Company has managed the impact of potential price declines by developing a balanced portfolio of fixed price and market sensitive contracts and commodity hedging. Approximately 16% of average gas production at December 31, 1998 was sold subject to fixed price sales contracts. These fixed price contracts are at prices ranging from $1.50 to $5.00 per Mcf. The fixed price contracts with terms of less than one year, between one and five years and greater than five years constitute approximately 41%, 50% and 9%, respectively, of the volume sold under fixed price contracts.

From time to time, the Company enters into oil and natural gas price hedges to reduce its exposure to commodity price fluctuations. At December 31, 1998, approximately 13% of the Company's existing market sensitive 1999 production was fixed under hedging agreements which expire on a monthly basis in January and April through October. Subsequent to December 31, 1998, the Company entered into additional hedging agreements, which increased the percentage of the Company's existing market sensitive production covered by hedging arrangements to 30%. In the future, the Company may hedge a larger percentage of its production, however, it currently anticipates that such percentage would not exceed 80%. Although these hedging activities provide the Company some protection against falling prices, these activities also reduce the potential benefits to the Company of price increases above the levels of the hedges.

The Company has an above market gas contract with a major Texas gas utility company, which expires June 30, 2000. During 1998, the Company sold 11% of its gas production under this contract. At December 31, 1998 the price received pursuant to the contract was $3.82 per Mcf ($3.40 per Mmbtu). The agreement provides for a price escalation of $0.05 per Mmbtu on July 1 of each year.

INDEPENDENT PRODUCER FINANCE ("IPF")

As part of the Merger, in August 1998 the Company acquired its Independent Producer Finance operations. IPF provides capital to small oil and gas producers to finance specifically identified acquisition and development projects. IPF advances money to producers in exchange for a term overriding royalty interest in their projects. The overrides are dollar-denominated and are calculated to provide IPF with a contractually specified rate of return that typically ranges between 10% and 25%. While there is no formal policy in place, the Company generally makes advances of less than $5 million per producer project. IPF funds its business principally with a combination of internally generated cash and borrowings under a bank credit facility. Through December 1998, approximately $31.1 million of the outstanding portfolio had been financed through internally generated cash flows with the remainder coming from borrowings under the credit facility. At December 31, 1998 the portfolio had 60 open transactions with a book value of $77.2 million (net of $14.0 million in allowances against its portfolio of receivables) with underlying reserves having Present Value of $92.2 million. The IPF reserves and Present Value are not included in Range's consolidated oil and gas reserve disclosure. During 1998, IPF expenses were comprised of $.5 million general and administrative expenses, $1.6 million of interest expense and a $5.9 million allowance against its portfolio of receivables.

IPF is staffed with four petroleum engineers and geologists who identify and evaluate each project. These technical personnel are all professional with degrees in petroleum engineering or geology. The staff has between 14 and 18 years of experience, averaging 17 years of experience in the oil and gas industry ranging from operations to strategic planning and analysis and production engineering. These professionals are responsible for defining transaction risk, establishing reserve coverage and negotiating the contractual rate of return. The transactions are structured to minimize risk by focusing on asset coverage ratios and taking direct title to the overriding royalty interests. As dollar-denominated term overriding royalties, the transactions leave the majority of the commodity price risk with the producer.

IPF provides capital to small oil and gas producers who are generally ignored by traditional financial institutions. These producers typically are denied access to traditional financing arrangements for one of four primary reasons: (i) they are too small to have access to debt and equity security markets; (ii) private equity and debt financing is too restrictive and expensive; (iii) few commercial banks are interested in small energy loans; and (iv) bank consolidations have raised the size threshold for lending. IPF has doubled its portfolio each year since 1993 despite its limited geographic scope, transaction size and marketing effort. Range expects demand for IPF funding to increase, as oil and gas acquisition and divestiture activities continue and consolidation of the banking industry reduces the supply of traditional bank financing for small transactions. IPF's growth has been financed through borrowing under its revolving credit facility and internally generated cash flow. The IPF Facility is recourse only to the assets of the IPF subsidiary. On March 10, 1999, the borrowing base on the IPF Facility was $60.1 million which did not exceed the amounts outstanding on that date. The Company is currently in the process of completing a borrowing base redetermination. Upon completion of the redetermination, the Company believes the borrowing base amount will decrease slightly and that the outstanding obligations at that time will not exceed the borrowing base.

Our IPF program involves an up-front cash payment for the purchase of a term overriding royalty interest through which we receive an agreed upon share of revenues from identified properties. The producer's obligation to deliver these revenues to us is non-recourse to the producer. The producer generally is not liable to us for any failure to meet its payment obligation unless the producer fails to operate prudently, there is a title failure or certain other events within the producer's control occur. Consequently, our ability to realize successful investments through our producer finance business is subject to our ability to estimate accurately the volumes of recoverable reserves from which the applicable production payment is to be discharged and the operator's ability to recover these reserves. Because our interest constitutes a property interest, if a producer is declared bankrupt or insolvent, our interest would be outside of the reach of the producer's creditors. However, if a creditor, the producer as debtor-in-possession or a trustee for the producer in a bankruptcy proceeding were to argue successfully that the transaction should be characterized as a loan, we may have only a creditor's claim for repayment of the amounts advanced. Our ownership in these production payments is a non-operating interest. As a result, our ownership of these production payments should not expose us to liability resulting from the ownership of direct working interests, such as environmental liabilities and liabilities for personal injury or death or property damage. Finally, the producer's obligation to deliver a specified share of revenues to us is subject to the ability of the burdened reserves to produce such revenues. As a result, we bear the risk that future revenues we receive will be insufficient to amortize the purchase price we paid for the interest or to provide any investment return to us.

The following is a table of operating statistics for the IPF operations:

	As of or for the period ended December 31,				
	1994	1995	1996	1997	1998
Total dollars of advances	$5,438	$5,489	$19,100	$40,150	$45,822
Number of advances made	10	10	27	39	75
Average size of advance	$ 544	$ 549	$ 707	$ 1,029	$ 611
Average rate of return	28.8%	20.0%	17.7%	14.5%	16.8%

INTEREST AND OTHER

The Company earns interest on its cash and investment accounts, as well as on various notes receivable. Other income in 1998 was comprised principally of gains on sales of marketable equity securities and gains on sales of non-strategic properties. The Company expects to continue to sell properties that are marginal or are not strategic. Interest and other income in 1998 amounted to $2.3 million, representing 2% of total revenues.

COMPETITION

The Company encounters substantial competition in acquiring oil and gas leases and properties, marketing oil and gas, securing personnel and conducting its drilling and field operations. Many competitors have financial and other resources which substantially exceed those of the Company. The competitors in development, exploration, acquisitions and production include the major oil companies in addition to numerous independents, individual proprietors and others. 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 in the future will be dependent upon its ability to select and acquire suitable producing properties and prospects for future drilling.

The Company's acquisitions have been partially financed through issuances of equity and debt securities and internally generated cash flow. There is competition for capital to finance oil and gas acquisitions and drilling. The ability of the Company to obtain such financing is uncertain and can be affected by numerous factors beyond its control. The inability of the Company to raise capital in the future could have an adverse effect on certain areas of its business.

GOVERNMENTAL REGULATION

The Company's operations are affected from time to time in varying degrees by political developments and federal, state and local laws and regulations. In particular, oil and natural gas production and related operations are or have been subject to price controls, taxes and other laws and regulations relating to the oil and gas industry. Failure to comply with such laws and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas 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 predict the future cost or impact of complying with such laws and regulations.

ENVIRONMENTAL MATTERS

The Company's oil and natural gas exploration, development, production and pipeline gathering 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 gathering activities, 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 the Company's operations. In addition, these laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist. The regulatory burden on the oil and gas industry increases the cost of doing business and consequently affects its profitability. Changes in environmental laws and regulations occur frequently, and any 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 oil and gas industry in general. While management believes that the Company is in substantial compliance with current applicable environmental laws and regulations and the Company has not experienced any material adverse effect from compliance with these environmental requirements, there is no assurance that this will continue in the future. The Company did not have any material capital expenditures in connection with environmental regulation for 1998. The Company does not anticipate any material capital expenditures for environmental regulation during 1999.

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also 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 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 and 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 thus such wastes may become subject to liability and regulation under CERCLA. State initiatives to further regulate the disposal of oil and natural gas wastes are also pending in certain states, and these various initiatives could have a similar impact on the Company.

Stricter standards in environmental legislation may be imposed in 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 natural gas exploration and production wastes as "hazardous wastes" and make the reclassified wastes subject to more stringent handling, disposal and clean-up restrictions. If such legislation were to be enacted, it could have a significant impact on the operating costs of the Company, as well as the oil and gas industry in general. Compliance with environmental requirements generally could have a material adverse effect upon 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 in the future.

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 (NPDES) permits prohibit or are expected to prohibit within the next year the discharge of produced water and sand, and some other substances related to the oil and gas industry, to coastal waters. Although the costs to comply with zero discharge mandated under federal or state law may be significant, the entire industry will experience similar costs and the Company believes that these costs will not have 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 natural 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 involved in oil and gas exploration and production.

In addition, 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.

EMPLOYEES

As of January 1, 1999, the Company had 390 full time employees, of whom 223 were field personnel. None are covered by a collective bargaining agreement and management believes that its relationship with its employees is good.

ITEM 2. PROPERTIES

On December 31, 1998, the Company held working interests in 8,427 gross (6,755 net) productive oil and gas wells and royalty interests in 373 additional wells. The properties contained, net to the Company's interest, estimated proved reserves of 633 Bcf of gas and 27 million barrels of oil and natural gas liquids or a total of 796 Bcfe.

PROVED RESERVES

The following table sets forth estimated proved reserves for each year in the five year period ended December 31, 1998.

	1994	1995	1996	1997	1998
Natural gas (Mmcf)					
Developed	97,251	174,958	207,601	369,786	436,062
Undeveloped	52,119	57,929	87,993	204,632	197,255
Total	149,370	232,887	295,594	574,418	633,317
Oil and NGL (Mbbls)					
Developed	6,431	8,880	10,703	14,971	19,649
Undeveloped	2,018	1,983	3,972	14,803	7,480
Total	8,449	10,863	14,675	29,774	27,129
Total (Mmcfe) (a)	200,064	298,065	383,644	753,062	796,091

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

In connection with the evaluation of its reserves, the Company engaged the following independent petroleum consultants: Netherland, Sewell & Associates, Inc. (Southwest and Gulf Coast), H.J. Gruy and Associates, Inc. (Southwest and Gulf Coast), DeGoyler and MacNaughton (Gulf Coast), Wright & Company, Inc. (Appalachia), and Clay, Holt & Klammer (Appalachia). These engineers have been employed primarily based on geographic expertise as well as their history in engineering certain of the acquired properties. At December 31, 1998, approximately 85% of the proved reserves set forth above were evaluated by independent petroleum consultants, while the remainder were evaluated by the Company's engineering staff. All estimates of oil and gas reserves are subject to significant uncertainty.

The following table sets forth as of December 31, for the periods presented, the estimated future net cash flow from and the Present Value of the proved reserves in millions.

	1994	1995	1996	1997	1998
Future net cash flow	$ 271	$ 413	$ 941	$ 1,276	$ 1,020
Present value					
Pre-tax	151	229	492	632	555
After tax	120	174	351	511	517

Future net cash flow represents future gross cash flow from the production and sale of proved reserves, net of production costs (including production taxes, ad valorem taxes and operating expenses) and future development costs. Such calculations, which are prepared in accordance with the Statement of Financial Accounting Standards No. 69 "Disclosures about Oil and Gas Producing Activities" are based on cost and price factors at December 31, 1998. Average product prices in effect at December 31, 1998 were $10.00 per barrel of oil and $2.25 per Mmbtu of gas. There can be no assurance that the proved reserves will be developed 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 December 31, 1998.

SIGNIFICANT PROPERTIES

The Company's reserves at December 31, 1998 were grouped into three regions, Southwest, Gulf Coast and Appalachia. Properties in the Southwest region are divided into two divisions, the Permian and Midcontinent. At December 31, 1998, the Company's properties included working interests in 8,427 gross (6,755 net) productive oil and gas wells and royalty interests in 373 additional wells. The Company also held interests in 830,285 gross (445,817 net) undeveloped acres. The following table sets forth summary information with respect to the Company's estimated proved oil and gas reserves at December 31, 1998.

	Pre-tax Present Value				
	Amount (In thousands)	%	Oil & NGL (Mbbls)	Natural Gas (Mmcfe)	Total (Mmcf)
Southwest					
Permian	$158,455	28%	21,997	138,865	270,847
Midcontinent	49,287	9%	1,005	58,155	64,185
Subtotal	207,742	37%	23,002	197,020	335,032
Gulf Coast	154,298	28%	3,298	144,187	163,975
Appalachia	193,181	35%	829	292,110	297,084
Total	$555,221	100%	27,129	633,317	796,091

SOUTHWEST REGION

The Company's Southwestern properties are situated in the Permian and Val Verde Basins of west Texas, the Anadarko Basin of western Oklahoma, the Texas panhandle and the East Texas Basin. Reserves in these basins represent 37% of total Present Value at December 31, 1998. Southwestern proved reserves totaled 335 Bcfe, of which approximately 59% were natural gas. At December 31, 1998, the Southwest Region properties had a development inventory of 598 proven drilling locations and recompletions.

Permian. The Permian business division properties, located in the Permian and Val Verde Basins of west Texas, contained 271 Bcfe of proved reserves, or 28% of total Present Value. Net daily production averages 5,719 barrels of oil and NGL and 29 Mmcf of gas. Producing wells total 2,196 (1,221 net), of which the Company operates 86% on a total reserve basis. Major producing properties include the Sonora area, Sterling area, Big Lake area, and Fuhrman-Mascho fields. 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. Sterling area gas production is liquids-rich and is transported to the Company's 25,000 Mcf/d gas plant, which processes gas from the Company's operated properties, as well as gas produced by third parties. The Big Lake and Fuhrman-Mascho properties produce primarily oil from the San Andres/Grayburg formations at depths ranging from 2,500 feet to 4,600 feet. At December 31, 1998, the Permian properties contained a development inventory of 310 recompletions and 211 infill drilling locations.

Midcontinent. The Midcontinent business division properties, located in the Anadarko Basin of western Oklahoma and the Texas panhandle, held proved reserves of 64 Bcfe. These reserves, representing 9% of the total Present Value, were 91% natural gas. Of 326 gross (190 net) wells, the Company operates 93%. The unit's largest property is in the Okeene Field, including over 191 operated wells. At December 31, the Midcontinent properties produce an average of 293 barrels of oil and 19 Mmcf of gas per day. The properties produce from a variety of sands and carbonates in both structural and stratigraphic traps on the Hunton, Red Fork, Simpson and Morrow formations at 6,000 to 12,000 foot depths. The Midcontinent development inventory includes 44 recompletions and 33 drilling locations.

GULF COAST REGION

The Company's 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 Gulf Coast business unit properties contained 164 Bcfe of proved reserves at December 31, 1998, or 28% of the total Present Value. The reserves were 88% natural gas. At December 31, 1998 daily production from the Gulf Coast properties averaged 1,576 barrels of oil and 60 Mmcf of gas. The properties are located from south Texas to Mississippi. Major fields onshore include Hagist Ranch, Alta Mesa, and Oakvale. These fields produce from the Wilcox, Frio, Yegua, Vicksburg, Miocene, and Hosston formations at depths ranging from 1,000 to 16,000 feet. In total, the onshore properties include 178 wells (131 net), of which 78% are Company operated. The offshore properties in the Gulf of Mexico include 54 platforms offshore in water depths ranging from 20 to 400 feet. The entire Gulf Coast region is characterized by relatively complex geology, multiple producing horizons and substantial exploitation and exploration potential. At December 31, 1998, the Gulf Coast properties had a proven development inventory of 110 recompletions and 44 drilling locations.

APPALACHIAN REGION

At December 31, 1998, the Appalachian properties contained 297 Bcfe of proved reserves, representing 35% of the Company's total Present Value. The reserves are attributable to 5,932 gross wells (5,065 net wells) located in Pennsylvania, Ohio, West Virginia and New York. The Company operates 95% of these wells. The reserves, which on an Mcfe basis are 98% natural gas, produce principally from the Medina, Clinton and Knox sequence of formations at depths ranging from 2,500 to 7,000 feet. Net daily production currently totals 43 Mmcf of gas and 316 barrels of oil. After initial flush production, these properties are characterized by gradual decline rates. Gas production is transported through over 2,700 miles of Company owned gas gathering systems and is sold primarily to utilities and industrial end-users.

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,				
	1994	1995	1996	1997	1998
Production					
Oil and NGL (Bbl)	640	913	1,068	1,794	2,655
Gas (Mcf)	6,996	12,471	21,231	38,409	45,193
Total (Mcfe) (a)	10,836	17,949	27,641	49,170	61,120
Revenues					
Oil and NGL	$ 9,743	$ 15,133	$ 20,425	$ 28,800	$ 30,084
Gas	14,718	22,284	47,629	101,217	105,509
Total	$ 24,461	$ 37,417	$ 68,054	$130,017	$135,593
Direct operating expenses (b)	8,130	11,302	20,676	31,481	39,001
Gross margin	$ 16,331	$ 26,115	$ 47,378	$ 98,536	$ 96,592
Average sales price					
Oil (Bbl)	$ 15.23	$ 16.57	$ 19.56	$ 18.22	$ 12.01
NGL (Bbl)	--	--	$ 10.22	$ 9.06	$ 8.26
Gas (Mcf)	$ 2.10	$ 1.79	$ 2.24	$ 2.64	$ 2.33
Mcfe (a)	$ 2.26	$ 2.08	$ 2.46	$ 2.64	$ 2.22
Average operating expense					
Per Mcfe	$ 0.75	$ 0.63	$ 0.75	$ 0.64	$ 0.64

(a) Oil and NGL is converted to Mcfe at a rate of 6 Mcf per barrel.
(b) Includes severance and production taxes.

PRODUCING WELLS

The following table sets forth information relating to productive wells at December 31, 1998. The Company owns royalty interests in an additional 373 wells. Wells are classified as oil or gas according to their predominant production stream.

	Gross Wells	Net Wells	Average Working Interest
Crude oil..................	1,613	1,071	66%
Natural gas................	6,814	5,684	83%
Total.................	8,427	6,755	80%

ACREAGE

The following table sets forth the developed and undeveloped acreage held at December 31, 1998.

	Gross	Net	Average Working Interest
Developed..................	1,033,199	756,537	73%
Undeveloped................	830,285	445,817	54%
Total.................	1,863,484	1,202,354	64%

DRILLING RESULTS

The following table summarizes drilling activities for the three years ended December 31, 1998.

	Year Ended December 31,					
	1996		1997		1998	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive....................	49.0	45.2	186.0	164.1	222.0	182.0
Dry...........................	3.0	2.2	7.0	5.4	12.0	8.8
Exploratory wells:						
Productive....................	7.0	3.4	12.0	2.8	9.0	3.9
Dry...........................	4.0	1.1	8.0	2.0	5.0	2.9
Total Wells:						
Productive....................	56.0	48.6	198.0	166.9	231.0	185.9
Dry...........................	7.0	3.3	15.0	7.4	17.0	11.7
Total....................	63.0	51.9	213.0	174.3	248.0	197.6

REAL PROPERTY

The Company owns a 24,000 square foot facility located on seven acres in Ohio. The Company leases approximately 56,000 square feet in Texas and Oklahoma under standard office lease arrangements that expire at various times through March 2004. All facilities are adequate to meet the Company's current needs and existing space could be expanded or additional space could be leased.

The Company owns various vehicles and other equipment which is 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 will be resolved without a material adverse effect on the Company's financial position.

In July 1997, a gas utility filed an action in the State District Court of Texas. In the lawsuit, the gas utility asserted a breach of contract claim arising out of a gas purchase contract. Under the gas utility's interpretation of the contract, it sought, as damages, the reimbursement of the difference between the above-market contract price it paid and market price on a portion of the gas it has taken beginning in July 1997. In May 1998, the court granted a partial summary judgment on the contract interpretation issue in favor of the gas utility. The summary judgment allows the utility to take or pay for a limited volume of gas defined in the contract as the "contract volume" at the contract price. In October 1998, the gas utility dropped its damages claim and the state district court signed a final judgment in this case. Range has appealed to reverse the final judgment. Range believes, under its interpretation, the utility is required to take all legally produced gas at the contract price. If Range wins the appeal, the summary judgment will be reversed. The court of appeals may either declare the contract's interpretation in Range's favor or declare that the contract provisions at issue are ambiguous. In either event, the case will be remanded to the trial court for a factual determination of the parties' obligations and/or remedies under the contract. If Range loses the appeal, the summary judgment will be affirmed and no further court action will be required.

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 money damages. On September 3, 1998, the parties executed a Memorandum of Understanding (the "MOU"), which represents a settlement in principle of the litigation. 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 also agreed to pay any court-awarded attorneys' fees and expenses of the plaintiffs' counsel in an amount not to exceed $290,000. The settlement in principle is subject to court approval and certain other conditions that have not been satisfied.

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 the Merger the stock was listed under the symbol "LOM". During 1998, trading volume averaged 144,236 shares per day. On March 9, 1999, the closing price of the Common Stock was $2 9/16. The following table sets forth the high and low sales prices as reported on the NYSE Composite transaction tape on a quarterly basis for the periods indicated.

	High	Low	Common Dividends
1997			
First Quarter	$ 23 5/8	$ 16	$ .02
Second Quarter	19	16	.02
Third Quarter	20 1/8	14	.03
Fourth Quarter	20 3/16	15 1/2	.03
1998			
First Quarter	17 1/2	13 1/4	.03
Second Quarter	16 11/16	9 3/4	.03
Third Quarter	10 7/16	6 1/16	.03
Fourth Quarter	6 13/16	2 15/16	.03

DIVIDENDS

Dividends on the Common Stock were initiated in late 1995 and have been paid in each quarter since that time. The Convertible Preferred Stock is entitled to receive cumulative quarterly dividends at the annual rate of $2.03 per share. If there is any arrearage in dividends on preferred stock, the Company may not pay dividends on the Common Stock. The Company has never been in arrears in the payment of preferred dividends.

The payment of dividends is subject to declaration by the Board of Directors and may depend on earnings, capital expenditures and market factors existing from time to time. Given the depressed oil and gas price environment, the Company may reduce or eliminate future dividends. The bank credit facility and the indenture for the 6% Convertible Subordinated Debenture and 8.75% Senior Subordinated Notes contain restrictions on the Company's ability to pay dividends on capital stock. Under the most restrictive of these provisions, the Company could have paid $10.4 million of dividends as of December 31, 1998.

HOLDERS OF RECORD

At March 9, 1999, the number of holders of record of the Common Stock and Convertible Preferred Stock were approximately 3,478 and 1, respectively.

ITEM 6. SELECTED FINANCIAL DATA

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

	As of or for the Year Ended December 31,				
	1994	1995	1996	1997	1998
	(In thousands, except per share data)				
OPERATIONS					
Revenues	$ 26,637	$ 41,169	$ 75,341	$ 145,417	$ 148,929
Net income (loss)	2,619	4,390	12,615	(23,332)	(175,150)
Earnings (loss) per share	.25	.31	.71	(1.31)	(6.82)
Earnings (loss) per share - dilutive	.25	.31	.69	(1.31)	(6.82)
Dividends per common share	-	0.01	0.06	0.10	0.12
BALANCE SHEET					
Working capital	$ 1,002	$ 4,563	$ 12,896	$ (2,051)	$ (9,484)
Oil and gas properties, net	112,964	176,702	229,417	623,807	662,099
Total assets	141,768	214,788	282,547	758,833	921,612
Senior debt	61,885	83,035	61,780	186,712	367,050
Non-recourse debt of IPF subsidiary	-	-	-	-	60,100
Subordinated debt	-	-	55,000	180,000	180,000
Trust convertible preferred securities	-	-	-	120,000	120,000
Stockholders' equity	43,248	99,367	117,529	196,950	133,222

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

	1997			
	Mar. 31	June 30	Sept. 30	Dec. 31
Revenues	$ 36,881	$ 32,069	$ 35,069	$ 41,398
Net income (loss) (a)	6,562	2,369	2,809	(35,072)
Earnings (loss) per share (a)	.35	.09	.11	(1.73)
Earnings (loss) per share - dilutive (a)	.32	.09	.11	(1.73)
Total assets (a)	667,522	674,835	780,620	758,833
Senior debt	210,230	206,711	309,007	186,712
Subordinated debt	180,000	180,000	180,000	180,000
Trust convertible preferred securities	-	-	-	120,000
Stockholders' equity (a)	218,146	219,769	223,961	196,950

	1998			
	Mar. 31	June 30	Sept. 30	Dec. 31
Revenues	$ 36,010	$ 32,273	$ 35,431	$ 45,215
Net income (loss) (b)	2,769	(944)	(66,907)	(110,068)
Earnings (loss) per share (b)	.10	(.07)	(2.57)	(3.13)
Earnings (loss) per share - dilutive (b)	.10	(.07)	(2.57)	(3.13)
Total assets (b)	800,252	822,984	1,036,111	921,612
Senior debt	234,905	252,200	368,176	367,050
Non-recourse debt of IPF subsidiary	-	-	53,795	60,100
Subordinated debt	180,000	180,000	180,000	180,000
Trust convertible preferred securities	120,000	120,000	120,000	120,000
Stockholders' equity(b)	199,058	195,747	234,575	133,222

(a) Includes a $58.7 million provision for impairment ($38.7 million after tax) recorded in the fourth quarter.
(b) Includes a $97.9 million provision for impairment ($63.6 million after tax) recorded in the third quarter and a $109.2 million provision for impairment ($92.6 million after tax) recorded in the fourth quarter.

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 due to rounding.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FACTORS EFFECTING FINANCIAL CONDITION AND LIQUIDITY

LIQUIDITY AND CAPITAL RESOURCES

General

The following discussion compares the Company's financial condition at December 31, 1998 to its financial condition at December 31, 1997. During 1998, the Company spent approximately $369 million on acquisition, development and exploration activities. At December 31, 1998, the Company had $11 million in cash and total assets of $921.6 million. During 1998, debt rose from $367.1 million to $607.2 million. At December 31, 1998, debt to total book capitalization was 71%.

In August 1998, the stockholders of the Company approved the Merger. Pursuant to the Merger, stockholders of Domain received approximately 13.6 million shares of the Company's Common Stock. The Company also purchased 3.8 million Domain shares for $50.5 million in cash. As a result of the Merger, Domain became a wholly-owned subsidiary of Lomak. Simultaneously, Lomak stockholders approved changing the company's name to Range Resources Corporation. In September 1998, the Company recorded a provision for impairment of $53.5 million on oil and gas properties acquired in the Merger. The provision for impairment reduced the carrying value of the properties acquired in the Merger and arose between the date the Merger agreement was signed and the closing date of the Merger due to declining market conditions and commodity prices in the oil and gas industry. Under the terms of the Merger Agreement, the Company was obligated to complete the Merger despite the decline in industry conditions. Although the Company's acquisition cost for the Domain oil and gas properties exceeded their fair value, the Company believes the merger affords other opportunities that provide value. In addition to a larger, more diversified oil and gas reserve base, the Merger increased Range's production and cash flow. The Company believes that Merger also broadened the depth and experience of its geological, geophysical and engineering personnel and provided opportunities for administrative cost savings.

In conjunction with the Merger, the Company purchased receivables relating to IPF. The amount of receivables at December 31, 1998 of $77.2 million includes an allowance for possible uncollectible receivables of $14 million. This allowance reflects uncertainty in the ultimate collection of these receivables due to the depressed price environment at December 31, 1998 and the effect of these prices on the producer's activities financed by IPF.

In December 1998, the Company implemented an overhead reduction program in response to the depressed energy price environment. In connection with its restructuring plan, the Company recorded a charge of $3.1 million in December 1998. The charge includes $2.1 million for the estimated costs to terminate 54 employees. The terminated employees were comprised as follows: 33 in operations; 11 in exploration; 3 in Midland office; 3 in gas marketing; 2 in IPF; and 2 in investor relations. Additionally, the charge included $.6 million for estimated costs to exit lease and other contractual commitments and an additional $.4 million relating to costs associated with the closing of the Midland, Texas office, which was deemed to be uneconomical. The $.4 million of associated costs consisted of $.1 million of costs to exit the office lease and $.3 million of costs to exit two exploration agreements. The Midland office was responsible primarily for the operation of a portion of the Company's Permian assets. The operation of these assets has been consolidated in the Company's Fort Worth, Texas office. The Company did not receive any benefits related to the restructuring in 1998, as the plan did not commence until mid-December. The Company will receive benefits, in the form of lower general and administrative expenses, beginning in the first quarter of 1999. In addition, during 1999 the Company plans to sell assets and limit exploration and development capital expenditures to reduce debt.

The Company believes that its capital resources are adequate to meet the requirements of its business. However, future cash flows are subject to a number of variables including the level of production and oil and gas prices, and there can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain planned levels of capital expenditures.

Cash Flow

The Company's principal operating sources of cash include sales of oil and gas, revenues from transportation, processing and marketing and IPF revenues. The Company's cash flow is highly dependent upon oil and gas prices. Recent decreases in the market price of oil and gas have reduced cash flow and could reduce the borrowing base under the Credit Facility. As a result, the Company has reduced its development and exploration budget to between $35 million to $40 million in 1999. The 1999 expenditures will be funded by internally generated cash flow and therefore may be reduced further depending upon commodity prices. The Company increased its debt borrowings by $135.8 million during 1998. The proceeds from these borrowings combined with operating cash flows were used to fund approximately $108 million of cash payments for the acquisition of oil and gas properties and businesses, as well as $71.8 million of developmental drilling activities.

The Company's net cash provided by operations for the years ended December 31, 1996, 1997 and 1998 was $38.4 million, $77.1 million and $45.0 million, respectively. The decline in the Company's 1998 cash flow from operations is attributed to sharply lower energy prices, as well as increased interest expense resulting from higher outstanding debt balances incurred to finance acquisitions and development activities.

The Company's net cash used in investing for the years ended December 31, 1996, 1997 and 1998 was $69.7 million, $501.1 million and $172.3 million, respectively. Investing activities for these periods are comprised primarily of additions to oil and gas properties through acquisitions and development and, to a lesser extent, exploration and additions of field service assets. These uses of cash have historically been partially offset through the Company's policy of divesting those properties that it deems to be non-strategic. The Company's activities have been financed through a combination of operating cash flow, bank borrowings and capital raised through equity and debt offerings. The Company's net cash provided by financing for the years ended December 31, 1996, 1997 and 1998 was $36.8 million, $425.2 million and $128.5 million, respectively. Sources of financing used by the Company have been primarily borrowings under its Credit Facility and capital raised through equity and debt offerings. The Company increased its debt borrowings by $135.8 million during 1998. The proceeds from these borrowings combined with operating cash flows were used to fund approximately $108 million of cash payments for the acquisition of oil and gas properties and businesses, as well as $71.8 million of developmental drilling activities.

Capital Requirements

In 1998, $81.5 million of capital was expended on development and exploration activities. In an effort to reduce outstanding debt the Company has significantly reduced its 1999 exploration and development capital budget to $35 million to $40 million. The development and exploration expenditures are currently expected to be funded entirely by internally generated cash flow. The development and exploration activities are highly discretionary and are expected to be reduced to levels below internally generated cash flow. The remaining cash flow will be available for debt repayment. See "Business--Development and Exploration Activities."

Bank Facilities

The Credit Facility permits the Company to obtain revolving credit loans and to issue letters of credit for the account of the Company from time to time in an aggregate amount not to exceed $400 million. The Borrowing Base is currently $385 million and is subject to semi-annual determination and certain other redeterminations based upon a variety of factors, including the discounted present value of estimated future net cash flow from oil and gas production. At the Company's option, loans may be prepaid, and revolving credit commitments may be reduced, in whole or in part at any time in certain minimum amounts. At December 31, 1998, the Company had $19.8 million of availability under the Credit Facility. Until amounts under the Credit Facility are reduced to $300 million or the redetermined borrowing base the interest rate will be LIBOR plus 1.75% and will increase to LIBOR plus 2.0% on May 1, 1999. When outstanding amounts are reduced to levels at or below $300 million or the redetermined borrowing base the interest rate on the Credit Facility will return to interest at prime rate or LIBOR plus 0.625% to 1.125% depending on the percentage of borrowing base drawn. If amounts outstanding under the Credit Facility exceed the higher of the redetermined borrowing base or $300 million on June 30, 1999, then the Company will have 10 days to repay any excess.

The Company plans to reduce outstanding amounts under the Credit Facility through operating cash flow and the sale of assets. The Company classified $52 million of assets as held for sale at December 1998. These assets represent properties located in Oklahoma, South Texas, West Texas, Gulf of Mexico and Michigan. The Company has entered into agreements with an independent firm to assist it in actively selling these assets. The properties held for sale, represented approximately 52 Bcfe of oil and gas reserves at December 31, 1998 and produced approximately 20 Mmcfe per day during December 1998. During 1998, $5.5 million of depletion expense was recorded related to these assets held for sale. These properties will not be depleted in 1999. The Company has reduced development and exploration of these properties in anticipation of their sale. Since the borrowing base is principally determined by the estimated value of oil and gas reserves these asset sales are expected to reduce the borrowing base and cash flows due to the loss of future production. The Company has developed a number of packages of oil and gas assets to offer for sale. The Company will utilize the proceeds from the sale of assets to reduce amounts outstanding under the Credit Facility. Additionally, the Company is considering the monetization of oil and gas assets whose proceeds would be used to reduce the Credit Facility. These monetizations could include contributing oil and gas operations or assets and debt into a joint venture, selling net profits interests in oil and gas properties or selling interests in oil and gas properties through an oil and gas royalty trust. The proceeds from the monetization of oil and gas assets are expected to reduce outstanding amounts under the Credit Facility. The Company's goal is to reduce debt as a percentage of total capitalization to levels at or below 50% within 12 to 24 months. At December 31, 1998, the Company classified $55.2 million of Credit Facility borrowings as current to reflect an estimate of the amounts outstanding at December 31, 1998 that will be repaid during 1999. Additional asset sales may be necessary to reduce outstanding amounts under the Credit Facility to meet future borrowing base requirements, however, at this time, the Company has no existing plans to sell any assets other than those stated above.

The IPF Facility is secured by substantially all of IPF's assets, is non-recourse to the Company and is exclusive of the Company's Credit Facility. The borrowing base under the IPF Facility is subject to redeterminations, which occur routinely during the year. On March 10, 1999, the borrowing base on the IPF Facility was $60.1 million, which did not exceed the amounts outstanding on that date. The Company is currently in the process of completing a borrowing base redetermination. Upon completion of the redetermination, the Company believes the borrowing base will decrease slightly and that the outstanding obligations at that time will not exceed the borrowing base. The IPF Facility bears interest at prime rate or interest at LIBOR plus a margin of 1.75% to 2.25% per annum depending on the total amount outstanding

Hedging Activities

Periodically, the Company enters into futures, option and swap contracts to reduce the effects of fluctuations in crude oil and natural gas prices. All futures, option and swap contracts entered into by the Company are solely to hedge the price volatility of oil and natural gas and not to speculate in the commodity markets. It is the Company's policy to have no more than 80% of its production hedged in any one quarter. At December 31, 1998, the Company had open contracts for gas price swaps of 6.4 Bcf of its production. The swap contracts are designed to set average prices ranging from $1.90 to $2.64 per Mmbtu. While these transactions have no carrying value, the Company's mark-to-market exposure under these contracts at December 31, 1998 was a net gain of approximately $44,500. These contracts expire monthly through October 1999. The gains or losses on the Company's hedging transactions are determined as the difference between the contract price and a reference price, generally closing prices on the NYMEX. The resulting transaction gains and losses are determined monthly and are included in oil and gas revenues in the period the hedged production or inventory is sold. Net gains or (losses) relating to these derivatives for the years ended December 31, 1996, 1997 and 1998 approximated $(.7) million, $(.9) million and $3.1 million respectively.

Interest Rate Risk

At December 31, 1998, Range had debt outstanding of $607.2 million. Of this amount, $180 million, or 30% bears interest at fixed rates averaging 7.9%. The remaining $427.2 million of debt outstanding at the end of 1998 bears interest at floating rates which averaged 6.6% at the end of 1998. The terms of the credit facilities in place allow interest rates to be fixed at Range's option for periods of between 30 and 180 days. At December 31, 1998, the Company had $100 million of borrowings subject to five interest rate swap agreements at rates of 5.71%, 5.59%, 5.35%, 4.82% and 5.64% through September 1999, October 1999, January 2000, September 2000 and October 2000, respectively. The interest rate swaps may be extended at the counterparties' option for two years. The agreements require that the Company pay the counterparty interest at the above fixed swap rates and require the counterparty to pay the Company interest at the 30-day LIBOR rate. The closing 30-day LIBOR rate on December 31, 1998 was 5.06%. A 10% increase in short-term interest rates on the floating-rate debt outstanding at the end of 1998 would equal approximately 66 basis points. Such an increase in interest rates would increase Range's 1999 interest expense by approximately $2.8 million, assuming borrowed amounts remain outstanding.

The above sensitivity analysis for interest rate risk excludes accounts receivable, accounts payable and accrued liabilities because of the short-term maturity of such instruments.

INFLATION AND CHANGES IN PRICES

The Company's revenues and the value of its oil and gas properties have been and will 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 substantially dependent on oil and gas prices. Oil and gas prices are subject to significant seasonal and other fluctuations that are beyond the Company's ability to control or predict. During 1998, the Company received an average of $12.01 per barrel of oil and $2.33 per Mcf of gas. Although certain of the Company's costs and expenses are affected by the level of inflation, inflation did not have a significant effect in 1998. Should conditions in the industry improve, inflationary cost pressures may resume.

RESULTS OF OPERATIONS

Comparison of 1998 to 1997

The Company reported a net loss for the year ended December 31, 1998 of $175.2 million, as compared to a net loss of $23.3 million for 1997. Due principally to the depressed energy price environment, the Company recorded a provision for impairment of $207.1 million ($156.2 million after tax) and $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).

Oil and gas revenues increased 4% to $135.6 million. During the year, oil and gas production volumes increased 24% to 61.1 Bcfe, an average of 167,500 Mmcfe per day. The increased revenues recognized from production volumes were negatively impacted by a 16% decrease in the average price received per Mcfe of production 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 recorded gas revenues related to an above market gas contract with a utility company representing 4.0 Bcf of gas production at an average price of $3.77 per Mcf (approximately $15.1 million of gas revenue). Had this gas been sold on the same terms as other production was sold in the same geographical region ($3.16 per Mcf), it would have resulted in a reduction in gas revenues of approximately $2.4 million. This gas contract expires June 30, 2000. If gas contracts cannot be found to replace the pricing received from this above-market contract, the Company will have to sell such gas subject to current market prices. Depending upon the market for natural gas at that time, this could have an effect on the Company's future revenues and liquidity. As a result of the Company's larger base of producing properties and production, oil and gas 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 during both periods.

Transportation, processing and marketing revenues decreased 14% to $6.7 million versus $7.8 million in 1997, the decrease was principally due to the sale of a gas processing plant in the San Juan Basin and a drop in natural gas liquid prices which lowered gas processing revenues. IPF income has been recorded for periods following the Merger. IPF income consists of the interest portion of the term overriding royalty interests. During 1998, IPF expenses included $.5 million of administrative expenses, $1.6 million of interest expense and a $5.9 million valuation allowance.

Exploration expense increased 346% to $11.3 million due to the Company's higher levels of seismic and exploratory drilling activity. During 1998 the Company spent $4.3 million on 5 exploratory dry holes compared to $294,000 of dry hole costs in 1997.

General and administrative expenses increased 74% from $5.3 million in 1997 to $9.2 million in 1998. As a percentage of revenues, general and administrative expenses were 6% in 1998 as compared to 4% in 1997. The increase was due to higher personnel costs associated with the Company's growth, as well as, increased legal expenditures during 1998. In December 1998, the Company implemented an overhead reduction program in response to the depressed energy price environment. 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 levels of non-strategic assets sales. Interest expense increased 50% to $40.6 million as compared to $27.2 million in 1997. This was primarily a result of the higher average outstanding debt balance during the year due to the financing of acquisitions and drilling activities. The average outstanding balances on the Credit Facility were $192.1 million and $271.6 million for 1997 and 1998, respectively. The weighted average interest rate on these borrowings were 7.3% and 6.7% for the years ended December 31, 1997 and 1998, respectively.

Depletion, depreciation and amortization increased 9% compared to 1997 as a result of increased production volumes. This 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. During 1998, the Company recorded $5.5 million of depletion expense on properties classified as assets held for sale at year end.

The Company recorded a provision for impairment due to the effect that reserve revisions due to drilling results and depressed oil and gas prices had on its proved and unproved reserves during 1998. The following are the properties impaired during 1998 (in thousands):

Property	Reason for Impairment	Impairment Amount
Sonora/Oakridge properties	Reserve revisions due to drilling results	$ 65,712

Sonora/Oakridge unproved acreage	Reserve revisions due to drilling results	20,089
Mill Strain unit	Decline in crude oil prices	1,018
Various West Texas properties	Decline in crude oil prices	1,506
West Delta 30	Decline in crude oil prices	16,117
Michigan properties	Decline in natural gas prices	14,644
Various East Texas properties	Decline in crude oil prices	2,323
Matagorda Island 519	Decline in natural gas prices	15,643
Mobile Bay 864	Decline in natural gas prices	10,735
East & West Cameron	Decline in natural gas prices	19,905
Offshore unproved acreage	Decline in natural gas prices	9,177
South Texas unproved acreage	Decline in natural gas prices	19,922
Marketable securities	Decline in oil and gas equity securities determined to be other than temporary	10,337
		$ 207,128

The impairment estimate on oil and gas properties recorded in 1998 was based on estimates of future cash flows for each property in the two categories evaluated for impairment: proved properties and unproved properties. The impairment evaluation for proved properties utilized only proved reserves and the impairment evaluation for unproved properties utilized only unproved reserves. Future cash flows include revenues from anticipated oil and natural gas production, severance taxes, direct operating costs and capitalized costs. 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 the present value of the future cash flows of unproved properties discounted at 10% or considers such other information the Company believes is relevant in evaluating the properties' fair value. Such other information may include the Company's geological assessment of the area, other acreage purchases in the area, or the properties' uniqueness. The present value of future cash flows from such properties has been adjusted for the Company's assessment of risk related to the unproved properties. In assessing the risk associated with unproved properties, the Company considers the recoverability of unproved reserves that have been classified as probable and possible reserves. Probable reserves are reserves not reasonably certain or proved, yet are "more likely to be recovered than not." Possible reserves are reasonably possible but "less likely to be recovered than not." The following is a table of index prices used in the calculation of the revenues estimated from oil and natural gas production over the anticipated life of the properties. These prices were then adjusted for the effect of the Company's production subject to existing sales contracts, and are not necessarily indicative of actual prices received by the Company at the dates of the impairment charges.

Year	Oil prices	Gas prices
1999	$ 12.62 - 13.25	$ 1.94 - 2.25
2000	14.50 - 16.00	2.23 - 2.30
2001	15.60 - 16.50	2.30 - 2.37
2002	16.44 - 17.10	2.35 - 2.44
2003	17.00 - 17.61	2.40 - 2.51
2004	17.50 - 18.14	2.45 - 2.59
2005	17.90 - 18.69	2.50 - 2.67
2006	18.35 - 19.25	2.58 - 2.75
2007	18.81 - 19.82	2.63 - 2.83
2008	19.28 - 20.42	2.69 - 2.91
2009	19.76 - 21.03	2.75 - 3.00

Severance taxes, direct operating costs and capitalized costs were estimated based on the Company's historical operating experience. These costs and expenses were escalated at 3% per year for 10 years and held constant thereafter. These prices were applied to production profiles developed by the Company's engineers using estimates of proved reserves and unproved reserves. The impairment estimates were determined based on the difference between the carrying value of the assets and the present value of future cash flows discounted at 10%. It is reasonably possible that a change in reserve or price estimates could occur in the near term and adversely impact management's estimate of future cash flows and consequently the carrying value of properties.

At December 31, 1998, the Company compared the fair value of its available-for-sale marketable securities to their historical cost. Due to the fact that the fair values on certain individual securities were below their historical cost and the Company determined that these declines in value were other than temporary, it charged a $10.3 million impairment against these assets.

Comparison of 1997 to 1996

The Company reported a net loss for the year ended December 31, 1997 of $23.3 million, as compared to $12.6 million net income for 1996. During the fourth quarter of 1997, the Company recorded a provision for impairment with regard to certain of its oil and gas properties amounting to $58.7 million ($38.7 million after tax). Excluding the effects of the non-cash impairment charge, net income would have risen 22% to $15.4 million. The increase is principally the result of (i) higher production volumes, (ii) lower per unit operating and overhead costs and (iii) higher average product prices. During the year, oil and gas production volumes increased 78% to 49.2 Bcfe, an average of 134.7 Mmcfe per day. The increased revenues recognized from production volumes were aided by an 7% increase in the average price received per Mcfe of production to $2.64. The average oil price decreased 7% to $18.22 per barrel while average gas prices increased 18% to $2.64 per Mcf. During 1997, the Company recorded gas revenues related to an above market gas contract with a utility company representing 6.0 Bcf of gas production at an average price of $3.73 per Mcf ($22.4 million of gas revenue). Had this gas been sold on the same terms as other production that was sold in the same geographical region, it would have resulted in a reduction in gas revenues of $8.1 million. This gas contract expires June 30, 2000. Depending upon the market for natural gas at that time, the possibility exists that the expiration of this contract could have a material effect on the Company's future results of operations. As a result of the Company's larger base of producing properties and production, oil and gas production expenses increased 52% to $31.5 million in 1997 versus $20.7 million in 1996. The average operating cost per Mcfe produced decreased 15% from $0.75 in 1996 to $0.64 in 1997.

Transportation, processing and marketing revenues increased 100% to $7.8 million versus $3.9 million in 1996 principally due to production growth. Exploration expense increased 73% to $2.5 million due to the Company's increased involvement in seismic and exploratory drilling activity.

General and administrative expenses increased 33% from $4.0 million in 1996 to $5.3 million in 1997. As a percentage of revenues, general and administrative expenses were 4% in 1997 as compared to 5% in 1996. This decreasing trend reflects the spreading of administrative costs over a growing asset base.

Interest and other income rose 124% to $7.6 million primarily due to $3.2 million on gains from sale of marketable securities (which were not related to hedging activities), and $4.1 million from the gain on the sale of non-strategic assets. Interest expense increased 263% to $27.2 million as compared to $7.5 million in 1996. This was primarily as a result of the higher average outstanding debt balance during the year due to the financing of acquisitions and drilling activities. The average outstanding balances on the Credit Facility were $107.2 million and $192.1 million for 1996 and 1997, respectively. The weighted average interest rate on these borrowings were 6.7% and 7.3% for the years ended December 31, 1996 and 1997, respectively.

Depletion, depreciation and amortization increased 148% compared to 1996 as a result of increased production volumes and increased depletion rates per volume. The Company-wide depletion rate was $0.73 per Mcfe in 1996 and $1.03 per Mcfe in 1997.

The Company recorded a provision for impairment due to the effect that depressed oil and gas prices had on its proved reserves during 1997. The following are the properties impaired during 1997 (in thousands):

Property	Reason for Impairment	Impairment Amount
O'Keene properties	Decline in natural gas prices	$ 16,538
Various offshore properties	Decline in natural gas prices	5,354
Various south Texas properties	Decline in natural gas prices	10,022
Fuhrman Mascho properties	Decline in crude oil prices	26,786
		$ 58,700

The impairment estimate recorded in 1997 was based on estimates of future cash flows for each property in the two categories evaluated for impairment: proved properties and unproved properties. The impairment evaluation for proved properties utilized only proved reserves and the impairment evaluation for unproved properties utilized only unproved reserves. Future cash flows include revenues from anticipated oil and natural gas production, severance taxes, direct operating costs and capitalized costs. Based on management's estimates, crude oil price estimates used to calculate these future net cash flows were based upon West Texas Intermediate posted price that was $16.00 per barrel for 1998 and was held constant thereafter. Natural gas price estimates were based upon NYMEX future price that was $2.15 per Mcf for 1998 and was held constant thereafter. These prices were then adjusted for the effect of the Company's production subject to existing sales contracts, and are not necessarily indicative of actual prices received by the Company at the dates of the impairment charges.

Severance taxes, direct operating costs and capitalized costs were estimated based on the Company's historical experience in its areas of operations. The impairment estimates were determined based on the difference between the carrying value of the assets and the present value of future cash flows discounted at 10%. It is reasonably possible that a change in reserve or price estimates could occur in the near term and adversely impact management's estimate of future cash flows and consequently the carrying value of properties.

Comparison of 1996 to 1995

The Company reported net income for the year ended December 31, 1996 of $12.6 million, a 187% increase over 1995. The increase is the result of (i) higher production volumes, over 60% of which is attributable to acquisitions and the remainder of which is attributable to development activities,

(ii) increased prices received from the sale of oil and gas products and (iii) gains from asset sales. During the year, oil and gas production volumes increased 54% to 27.6 Bcfe, an average of 76 Mmcfe/d. The increased revenues recognized from production volumes were aided by an 18% increase in the average price received per Mcfe of production to $2.46. The average oil price increased 18% to $19.56 per barrel while average gas prices increased 25% to $2.24 per Mcf. As a result of the Company's larger base of producing properties and production, oil and gas production expenses increased 83% to $20.7 million in 1996 versus $11.3 million in 1995. The average operating cost per Mcfe produced increased 19% from $0.63 in 1995 to $0.75 in 1996 due to unsuccessful recompletion costs and increases in personnel costs. Exploration expense increased 185% to $1.5 million due to the Company's increased involvement in seismic and exploratory drilling. The Company participated in 11 exploratory wells in 1996 versus 7 exploratory wells in 1995.

Gas transportation and marketing revenues increased 60% to $3.9 million versus $2.4 million in 1995 principally due to production growth.

General and administrative expenses increased 45% from $2.7 million in 1995 to $4.0 million in 1996. As a percentage of revenues, general and administrative expenses were 5% in 1996 as compared to 7% in 1995. This decreasing trend reflects the spreading of administrative costs over a growing asset base.

Interest and other income rose 157% to $3.4 million primarily due to $1.4 million on gains from sales of marketable securities (which were not related to hedging activities), and $1.2 million from the gain on the sale of the Oklahoma well servicing assets. Interest expense increased 34% to $7.5 million as compared to $5.6 million in 1995. This was primarily as a result of the higher average outstanding debt balance during the year due to the financing of capital expenditures. The average outstanding balances on the Credit Facility were $73.3 million and $107.2 million for 1995 and 1996, respectively. The weighted average interest rate on these borrowings were 7.3% and 6.7% for the years ended December 31, 1995 and 1996, respectively.

Depletion, depreciation and amortization increased 50% compared to 1995 as a result of increased production volumes during the year. The Company-wide depletion rate was $0.73 per Mcfe in 1995 and 1996.

YEAR 2000

The Company has developed a plan (the "Year 2000 Plan") to address the Year 2000 issue caused by computer programs and applications that utilize two digit date fields rather than four to designate a year. As a result, computer equipment, software and devices with embedded technology that are date sensitive may be unable to recognize or misinterpret the actual date. This could result in a system failure or miscalculations causing disruptions of operations. The Company's Board of Directors has established a Year 2000 committee to review the adoption and implementation of the Year 2000 Plan.

Assessment has been substantially completed for the information technology ("IT") and non-IT systems for the Company, including IPF operations. The term "IT systems" includes personal computers, accounting / data processing software and other miscellaneous systems. Range's computerized accounting system, is the most date-sensitive IT systems equipment of the Company, was upgraded and tested to be Year 2000 compliant. The Company's personal computer systems will be compliant with minor upgrades provided by the software vendors and with the purchase of a nominal amount of additional computer equipment.

The non-IT systems include operational and control equipment with embedded chip technology that is utilized in the offices and field operations related to the Company and IPF's small oil and gas producers. The systems were reviewed as part of the Year 2000 Plan. Most of the wells are operated by non-computerized equipment. The potentially affected areas are the gas processing plant in the Midland Basin, telemetry that controls approximately 10% of the Company's wells and portable metering devices which are used on less than 2% of the Company's wells. These items do not affect a significant portion of Range's operations. Range is in the process of resolving the Year 2000 problems. The suppliers of the affected equipment are providing upgrades or modifications. The Company expects to complete this remediation process by June 30, 1999.

Range is also monitoring the compliance efforts of its significant suppliers, customers and service providers with whom it does business and whose IT and non-IT systems interface with those of the Company to ensure that they will be Year 2000 compliant. If they are not, such failure could affect the ability of the Company to sell its oil and gas and receive payments therefrom and the ability of vendors to provide products and services in support of the Company's operations. Although the Company has no reason to believe that its vendors and customers will not be compliant by the year 2000, the Company is unable to determine the extent to which Year 2000 issues will affect its vendors and customers. However, management believes that ongoing communication with and assessment of the compliance efforts of these third parties will minimize these risks.

The discussion of the Company's efforts and management's expectations relating to Year 2000 compliance contains forward-looking statements. Range is currently conducting a comprehensive analysis of the financial and operational problems that would be the most reasonably likely worst case scenario to result from failure by Range and significant third parties to complete efforts necessary to achieve Year 2000 compliance on a timely basis. The Company intends to establish a contingency plan of which the primary goals are to maintain continuity of operations, preserve Company assets and protect the environment. Range plans to complete the analysis of the most reasonably likely worst case scenario and contingency planning by the third quarter of 1999.

The total cost for the Year 2000 Project is not expected to be in excess of $180,000. Of this amount, approximately $65,000 had been incurred as of March 31, 1999.

Range presently does not expect to experience significant operational problems due to the Year 2000 issues. However, if all Year 2000 issues are not properly and timely identified, assessed, remediated and tested, there can be no assurance that the Year 2000 issue will not materially impact Range's results of operations or adversely affect its relationship with customers, vendors, or others. Additionally, there can be no assurance that the Year 2000 issues of other entities will not have a material impact on Range's systems or results of operations.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Reference is made to the Index to Financial Statements on page 28 for a listing of the Company's financial statements and notes thereto and for 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 that 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 current executive officers and directors of the Company are listed below, together with a description of their experience and certain other information. Each of the directors was elected for a one-year term at the Company's 1999 annual meeting of stockholders. Executive officers are appointed by the Board of Directors.

NAME	AGE	HELD OFFICE SINCE	POSITION WITH COMPANY
Thomas J. Edelman	48	1988	Chairman and Chairman of the Board
John H. Pinkerton	44	1988	President, Chief Executive Officer and Director
Michael V. Ronca	45	1998	Chief Operating Officer and Director
Robert E. Aikman	67	1990	Director
Anthony V. Dub	49	1995	Director
Allen Finkelson	52	1994	Director
Ben A. Guill	48	1995	Director
Jonathan S. Linker	50	1998	Director
Steven L. Grose	50	1980	Senior Vice President - Appalachia
Herbert A. Newhouse	54	1998	Senior Vice President - Gulf Coast
Catherine L. Sliva	40	1998	Senior Vice President - Independent Producer Finance
Chad L. Stephens	43	1990	Senior Vice President - Southwest
Thomas W. Stoelk	43	1994	Senior Vice President - Finance and Administration
Jeffery A. Bynum	44	1985	Vice President - Land and Corporate Secretary
Geoffrey T. Doke	32	1996	Vice President and Controller

Thomas J. Edelman, Chairman and Chairman of the Board of Directors, joined the Company in 1988. He served as its Chief Executive Officer until 1992. From 1981 to 1997, Mr. Edelman served as a director and President of Snyder Oil Corporation ("SOCO"), an independent, publicly traded oil and gas company. In 1996, Mr. Edelman was appointed Chairman, President 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 Petroleum Heat & Power Co., Inc., a Connecticut-based fuel oil distributor, Star Gas Corporation, a private company, which is the general partner of Star Gas Partners, L.P., a publicly-traded master limited partnership, which distributes propane gas, as well as Paradise Music & Entertainment, Inc.

John H. Pinkerton, President, Chief Executive Officer and a Director, joined the Company in 1988. He was appointed President in 1990 and Chief Executive Officer in 1992. 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 director of North Coast Energy, Inc. ("North Coast"), and Venus Exploration, Inc. publicly traded exploration and production companies in which Range owned 17.4% and 21.7%, respectively, at December 31, 1998.

Michael V. Ronca, Chief Operating Officer and a Director, joined the Company in 1998. Prior to joining Range, Mr. Ronca served as President and Chief Executive Officer of Domain Energy

Corporation. He was the founder and former President of Tenneco Ventures Corporation. Mr. Ronca was an employee of Tenneco for over 20 years. Other positions held at Tenneco included Administrative Assistant to the Chairman and CEO, with focus on acquisition and disposition analysis, strategic planning and operational issues.

Robert E. Aikman, a Director, joined the Company 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., President of OGP Technologies, 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. He was President of Enertec Corporation which was reorganized under Chapter 11 of the Bankruptcy Code in December 1994. 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, Texas Independent Producers and Royalty Owners Association and American Association of Petroleum Landmen. Mr. Aikman graduated from the University of Oklahoma in 1952.

Anthony V. Dub was elected to serve as a Director of the Company 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, was appointed a Director in 1994. Mr. Finkelson has been a partner at Cravath, Swaine & Moore since 1977, with the exception of the period from September 1983 through August 1985, when he was a managing director of Lehman Brothers Kuhn Loeb Incorporated. Mr. Finkelson was first employed by Cravath, Swaine & Moore as an associate in 1971. Mr. Finkelson received his Bachelor of Arts Degree from St. Lawrence University and his Doctor of Laws Degree from Columbia University School of Law.

Ben A. Guill, was elected to serve as a Director of the Company in 1995. In September 1998 Mr. Guill joined First Reserve Corporation as President of its Houston office. First Reserve is a private equity firm, dedicated to the energy industry. Prior to joining First Reserve, Mr. Guill was a Partner and Managing Director of Simmons & Company International, an investment banking firm located in Houston, Texas which focuses on the oil service and equipment industry. Mr. Guill had been with Simmons & Company since 1980. Prior to that Mr. Guill was with Blyth Eastman Dillon & Company from 1978 to 1980. Mr. Guill received his Bachelor of Arts Degree from Princeton University and his Masters Degree in Finance from the Wharton Graduate School of Business at the University of Pennsylvania.

Jonathan S. Linker has served as a Director of the Company since the Merger in August 1998. Mr. Linker has been a Managing Director of First Reserve since 1996, the President and a director of IDC Energy Corporation since 1987, and a Vice President and Director of Sunset Production Corporation since 1991. Mr. Linker earned a Bachelor of Arts degree in Geology from Amherst College, a Master of Arts degree in Geology from Harvard University and a Master of Business Administration degree from the Harvard Business School.

Steven L. Grose, Senior Vice President - Appalachia, joined the Company in 1980. Previously, Mr. Grose was employed by Halliburton Services, Inc. as a Field Engineer from 1971 until 1974. In 1974, he was promoted to District Engineer and in 1978, was named Assistant District Superintendent based in Pennsylvania. Mr. Grose is a member of the Society of Petroleum Engineers and is currently serving as

President of the Ohio Oil and Gas Association. Mr. Grose received his Bachelor of Science Degree in Petroleum Engineering from Marietta College.

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 30 years of operational and managerial experience in oil and gas exploration and production. Mr. Newhouse received his Bachelor's degree in Chemical Engineering from Ohio State University.

Catherine L. Sliva, Senior Vice President - Independent Producer Finance, joined the Company in connection with the Merger in August 1998. Prior to joining Range, Ms. Sliva served as Executive Vice President and Secretary of Domain Energy Corporation. She was formerly with Tenneco Ventures Corporation for 16 years. Ms. Sliva is a registered Petroleum Engineer and has over 18 years experience in petroleum engineering, economics, producer finance and strategic planning and analysis. She received her Bachelor's degree in Petroleum Engineering from Texas A&M 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 his Bachelor of Arts Degree in Finance and Land Management from the University of Texas.

Thomas W. Stoelk, Senior Vice President - Finance and Administration, joined the Company in 1994. Mr. Stoelk is a Certified Public Accountant and was a Senior Manager with Ernst & Young LLP. Prior to rejoining Ernst & Young LLP in 1986 he was with Partners Petroleum, Inc. Mr. Stoelk received his Bachelor of Science Degree in Industrial Administration from Iowa State University.

Jeffery A. Bynum, Vice President - Land and Corporate Secretary, joined the Company in 1985. Previously, Mr. Bynum was employed by Crystal Oil Company and Kinnebrew Energy Group. Mr. Bynum holds a Professional Certification with American Association of Petroleum Landmen and attended Louisiana State University in Baton Rouge, Louisiana and Centenary College in Shreveport, Louisiana.

Geoffrey T. Doke, Vice President and Controller, joined the Company in 1991. He was appointed Treasurer in 1996 and Controller in 1997. Previously, Mr. Doke served in the accounting department of Edisto Resources Corporation. Mr. Doke received his Bachelor of Business Administration Degree in Finance and International Business from Baylor University and his Master of Business Administration Degree from Case Western Reserve University.

The Range Board has established three committees to assist in the discharge of its responsibilities.

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

COMPENSATION COMMITTEE. The Compensation Committee reviews and approves executive salaries and administers bonus, incentive compensation and stock option plans of Range. This Committee advises and consults with management regarding pensions and other benefits and significant compensation policies and practices of Range. This Committee also considers nominations of candidates for corporate officer positions. The members of the Compensation committee are Messrs. Aikman, Guill and Finkelson.

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 executive compensation is incorporated herein by reference to the Company's Proxy Statement for its 1999 annual meeting of stockholders.

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 Proxy Statement for its 1999 annual meeting of stockholders.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Information with respect to certain relationships and related transactions is incorporated herein by reference to the Company's Proxy Statement for its 1999 annual meeting of stockholders.

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.

The Company's Current Report on Form 8-K, dated August 25, 1998, as amended by Form 8-K/A, dated November 9, 1998.

(c) Exhibits required by Item 601 of Regulation S-K.
Exhibits required to be filed by the Company 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: September 17, 1999

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 September 17, 1999	Thomas J. Edelman, Chairman and Chairman of the Board
/s/ John H. Pinkerton September 17, 1999	John H. Pinkerton, Chief Executive Officer, President and Director
/s/ Michael V. Ronca September 17, 1999	Michael V. Ronca, Chief Operating Officer, and Director
/s/ Thomas W. Stoelk September 17, 1999	Thomas W. Stoelk, Chief Financial Officer and Senior Vice President-Finance & Administration
/s/ Geoffrey T. Doke September 17, 1999	Geoffrey T. Doke, Chief Accounting Officer and Vice President and Controller
/s/ Robert E. Aikman September 17, 1999	Robert E. Aikman, Director
/s/ Allen Finkelson September 17, 1999	Allen Finkelson, Director
/s/ Anthony V. Dub September 17, 1999	Anthony V. Dub, Director
/s/ Ben A. Guill September 17, 1999	Ben A. Guill, Director
/s/ Jonathan S. Linker September 17, 1999	Jonathan S. Linker, Director

GLOSSARY

The terms defined in this glossary are used throughout this Prospectus.

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.

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.

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.

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 pre-tax present value, discounted at 10%, of future net cash flows from estimated proved reserves, 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.

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])

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, 1997 and 1998, and the related consolidated statements of income, stockholders' equity and cash flows for each of the three years in the period ended December 31, 1998. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. 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, 1997 and 1998, and the results of its operations and its cash flows for the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles.

ARTHUR ANDERSEN LLP

Cleveland, Ohio
February 19, 1999

RANGE RESOURCES CORPORATION

CONSOLIDATED BALANCE SHEETS
(IN THOUSANDS, EXCEPT PER SHARE DATA)

	December 31, 1997	December 31, 1998
ASSETS		
Current assets		
Cash and equivalents	$ 9,725	$ 10,954
Accounts receivable	29,200	30,384
IPF receivables (Note 4)	-	7,140
Marketable securities	5,777	3,258
Assets held for sale (Note 5)	-	51,822
Inventory and other	2,779	3,373
	47,481	106,931
IPF receivables, net (Note 4)	-	70,032
Oil and gas properties, successful efforts method	785,223	935,822
Accumulated depletion and impairment	(161,416)	(273,723)
	623,807	662,099
Transportation, processing and field assets	85,904	89,471
Accumulated depreciation	(9,730)	(15,146)
	76,174	74,325
Other	11,371	8,225
	$ 758,833	$ 921,612
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 26,878	$ 28,163
Accrued liabilities	10,048	15,773
Accrued payroll and benefit costs	3,195	5,156
Accrued interest	8,998	9,439
Accrued business restructuring costs (Note 13)	-	2,697
Current portion of debt (Note 6)	413	55,187
	49,532	116,415
Senior debt (Note 6)	186,712	311,875
Non-recourse debt of IPF subsidiary (Note 6)	-	60,100
Subordinated debt (Note 6)	180,000	180,000
Deferred taxes (Note 12)	25,639	-
Commitments and contingencies (Note 8)	-	-
Company-obligated preferred securities of subsidiary trust (Note 9)	120,000	120,000
Stockholders' equity (Notes 9 and 10)		
Preferred stock, $1 Par, 10,000,000 shares authorized, $2.03 convertible preferred, 1,149,840 issued and outstanding (liquidation preference $28,746,000)	1,150	1,150
Common stock, $.01 par, 50,000,000 shares authorized, 21,058,442 and 35,933,523 issued	211	359
Capital in excess of par value	217,631	334,817
Retained deficit	(22,412)	(203,396)
Other comprehensive income	370	292
	196,950	133,222
	$ 758,833	$ 921,612

SEE ACCOMPANYING NOTES.

RANGE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF INCOME
(IN THOUSANDS, EXCEPT PER SHARE DATA)

	Year Ended December 31,		
	1996	1997	1998
Revenues			
Oil and gas sales	$ 68,054	$ 130,017	$ 135,593
Transportation, processing and marketing	3,901	7,806	6,711
IPF income	-	-	4,370
Interest and other	3,386	7,594	2,255
	75,341	145,417	148,929
Expenses			
Direct operating	20,676	31,481	39,001
IPF expense	-	-	7,996
Exploration	1,460	2,527	11,265
General and administrative	3,966	5,290	9,215
Interest	7,487	27,175	40,642
Depletion, depreciation and amortization	22,303	55,407	60,153
Provision for impairment (1998 amount includes $37.7 million related to assets held for sale)	-	58,700	207,128
Business restructuring costs (Note 13)	-	-	3,147
	55,892	180,580	378,547
Income (loss) before taxes	19,449	(35,163)	(229,618)
Income taxes			
Current	729	684	278
Deferred	6,105	(12,515)	(54,746)
	6,834	(11,831)	(54,468)
Net income (loss)	$ 12,615	$ (23,332)	$(175,150)
Comprehensive income (loss) (Note 2)	$ 12,729	$ (24,524)	$(175,260)
Earnings (loss) per common share (Note 14)			
Basic	$ 0.71	$ (1.31)	$ (6.82)
Dilutive	$ 0.69	$ (1.31)	$ (6.82)

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)
Balance, December 31, 1995 ...	1,350	$ 1,350	13,323	$ 133	$ 101,773	$ (4,013)
Preferred dividends	-	-	-	-	-	(2,454)
Common dividends at $.06 per share	-	-	-	-	-	(857)
Common issued	-	-	887	9	8,687	-
Common repurchased	-	-	(36)	-	(406)	-
Conversion of 71/2 preferred	(200)	(200)	577	6	194	-
Net income	-	-	-	-	-	12,615
Balance, December 31, 1996 ...	1,150	1,150	14,751	148	110,248	5,291
Preferred dividends	-	-	-	-	-	(2,334)
Common dividends at $.10 per share	-	-	-	-	-	(2,037)
Common issued	-	-	6,307	63	107,293	-
Common repurchased	-	-	-	-	(107)	-
Compensation in connection with stock options	-	-	-	-	197	-
Net loss	-	-	-	-	-	(23,332)
Balance, December 31, 1997 ...	1,150	1,150	21,058	211	217,631	(22,412)
Preferred dividends	-	-	-	-	-	(2,334)
Common dividends at $.12 per share	-	-	-	-	-	(3,500)
Common issued	-	-	15,276	152	120,188	-
Common repurchased	-	-	(401)	(4)	(3,002)	-
Net loss	-	-	-	-	-	(175,150)
Balance, December 31, 1998 ...	1,150	$ 1,150	35,933	$ 359	$ 334,817	$(203,396)

SEE ACCOMPANYING NOTES.

RANGE RESOURCES CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS
(IN THOUSANDS)

	YEAR ENDED DECEMBER 31,		
	1996	1997	1998
Cash flows from operations:			
Net income (loss)	$ 12,615	$ (23,332)	$(175,150)
Adjustments to reconcile net income (loss) to net cash provided by operations:			
Depletion, depreciation and amortization	22,303	55,407	60,153
Provision for impairment	-	58,700	207,128
Valuation reserve of IPF receivables	-	-	5,918
Amortization of deferred offering costs	-	999	1,293
Deferred income taxes	6,105	(12,541)	(54,746)
Changes in working capital net of effects of acquired businesses:			
Accounts receivable	(494)	(11,079)	2,842
Marketable securities	(5,264)	(7,964)	(253)
Inventory and other	137	(1,981)	6,996
Accounts payable	5,385	17,825	(4,274)
Accrued liabilities	781	9,186	(3,068)
Gain on sale of assets and other	(3,123)	(8,154)	(1,817)
Net cash provided by operations	38,445	77,066	45,022
Cash flows from investing:			
Acquisition of businesses, net of cash	(13,950)	-	(41,170)
Oil and gas properties	(59,137)	(492,259)	(135,399)
Additions to property and equipment	(1,250)	(64,945)	(3,732)
IPF investments of capital	-	-	(12,649)
IPF repayments of capital	-	-	3,556
Proceeds on sale of assets	4,671	56,070	17,081
Net cash used in investing	(69,666)	(501,134)	(172,313)
Cash flows from financing:			
Proceeds from indebtedness	85,201	246,025	135,788
Repayments of indebtedness	(53,268)	(26)	(413)
Preferred stock dividends	(2,454)	(2,334)	(2,334)
Common stock dividends	(857)	(2,037)	(3,500)
Proceeds from trust preferred securities issuance, net	-	115,999	-
Proceeds from common stock issuance, net	8,315	67,648	1,985
Repurchase of common stock	(138)	(107)	(3,006)
Net cash provided by financing	36,799	425,168	128,520
Change in cash	5,578	1,100	1,229
Cash and equivalents at beginning of period	3,047	8,625	9,725
Cash and equivalents at end of period	$ 8,625	$ 9,725	$ 10,954
Supplemental disclosures of non-cash investing and financing activities:			
Purchase of property and equipment financed with common stock	$ -	$ 39,537	$ 116,469
Common stock issued in connection with benefit plans	381	398	1,887

SEE ACCOMPANYING NOTES.

RANGE RESOURCES CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) ORGANIZATION AND NATURE OF BUSINESS

Range Resources Corporation ("Range" or the "Company") is an independent oil and gas company engaged in development, exploration and acquisition primarily in three core areas: Southwest, Gulf Coast and Appalachia. In addition, through its IPF subsidiary, the Company provides financing to smaller independent oil and gas producers by purchasing term overriding royalty interests in oil and gas properties. Historically, the Company has increased its reserves and production through acquisitions, development and exploration. In pursuing this strategy, the Company has concentrated its activities in selected geographic areas. In each core area, the Company has established operating, engineering, geoscience, marketing and acquisition expertise.

In August 1998, the stockholders of the Company approved the acquisition via merger (the "Merger") of Domain Energy Corporation ("Domain"). Pursuant to the Merger, stockholders of Domain received approximately 13.6 million shares of the Company's Common Stock. The Company also purchased 3.8 million Domain shares for $50.5 million in cash. As a result of the Merger, Domain became a wholly-owned subsidiary of Lomak. Simultaneously, Lomak stockholders approved changing the company's name to Range Resources Corporation.

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

BASIS OF PRESENTATION

The accompanying financial statements include the accounts of the Company, all majority owned subsidiaries and its pro rata share of the assets, liabilities, income and expenses of certain oil and gas partnerships and joint ventures. Highly liquid temporary investments with an initial maturity of ninety days or less are considered cash equivalents.

REVENUE RECOGNITION

The Company recognizes revenues from the sale of its respective products in the period delivered. Revenue for services are recognized in the period the services are provided.

MARKETABLE SECURITIES

The Company has adopted Statement of Financial Accounting Standards ("SFAS") No. 115, "Accounting for Certain Investments in Debt and Equity Securities." Under Statement No. 115, debt and marketable equity securities are required to be classified in one of three categories: trading, available-for-sale, or held to maturity. The Company's equity securities qualify under the provisions of Statement No. 115 as available-for-sale. Such securities are recorded at fair value, and unrealized holding gains and losses, net of the related tax effect, are reflected as a separate component of comprehensive income. A decline in the market value of an available-for-sale security below cost that is deemed other than temporary is charged to earnings and results in the establishment of a new cost basis for the security. At December 31, 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. Realized gains and losses are determined on the specific identification method and are reflected in income.

INDEPENDENT PRODUCER FINANCE ("IPF")

Through IPF, Range acquires dollar denominated term overriding royalty interests in oil and gas properties owned by independent oil and gas producers. The Company accounts for the acquired term overriding royalty interests as receivables because the funds advanced to a producer for these interests are repaid from an agreed upon share of cash proceeds from the sale of production until the amount advanced plus a specified return or interest is paid. Only the interest portion of payments received from a producer is recognized as IPF income on the statement of income. The remaining cash receipts are recorded as a reduction in receivables on the balance sheet and as a return of capital on the statement of cash flows. The portion of the term overriding royalty interests classified as a current asset are those expected to be received as repayments over the next twelve month period. Periodically, the Company performs a review for possible uncollectible accounts receivable and provides for unrecoverable amounts in its allowance for uncollectible receivables. At December 31, 1998 the Company's allowance for uncollectible receivables totaled $14 million. During 1998, IPF expenses were comprised of $.5 million of general and administrative expenses, $1.6 million of interest expense and a $5.9 million allowance against its portfolio of receivables.

OIL AND GAS PROPERTIES

The Company follows the successful efforts method of accounting for oil and gas properties. Exploratory costs are capitalized pending determination of whether the well has found proved reserves. Exploratory costs which result in the discovery of proved reserves and the cost of development wells are capitalized. In the absence of a determination as to whether the reserves found from an exploratory well can be classified as proved, the costs of drilling such an exploratory well are not carried as an asset for more than one year following the completion of drilling. 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 6 Mcf per barrel. The depletion rates per Mcfe were $.73, $1.03 and $.89 in 1996, 1997 and 1998, respectively. Approximately $22.8 million, $111.2 million and $75.9 million of oil and gas properties were not subject to amortization as of December 31, 1996, 1997 and 1998, 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 1997 and 1998, the Company recorded provision for impairment of $58.7 million and $196.8 million respectively, which reduced the carrying value of certain oil and gas properties to what the Company estimates to have been their fair value at that time. The provision for impairment on the oil and gas properties was due to reserve revisions as a result of drilling results and declines in oil and gas prices in 1999 and due to declines in oil and gas prices in 1998. The proved impairment was determined based on the difference between the carrying amount of the assets and the present value of the future cash flows from proved properties discounted at 10%. Impairment is recognized only if the carrying amount of a property is greater than its expected undiscounted future cash flows. It is reasonable possible that a change in reserve or price estimates could occur in the near term 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	Reason for Impairment	Impairment Amount
Sonora/Oakridge properties	Reserve revisions due to drilling results	$ 65,712
Mill Strain unit	Decline in crude oil prices	1,018
Various West Texas properties	Decline in crude oil prices	1,506
West Delta 30	Decline in crude oil prices	16,117
Michigan properties	Decline in natural gas prices	14,644
Various East Texas properties	Decline in crude oil prices	2,323
Matagorda Island 519	Decline in natural gas prices	15,643
Mobile Bay 864	Decline in natural gas prices	10,735
East & West Cameron	Decline in natural gas prices	19,905
		$ 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 the present value of the future cash flows of unproved properties discounted at 10% or considers such other information the Company believes is relevant in evaluating the properties' fair value. Such other information may include the Company's geological assessment of the area, other acreage purchases in the area, or the properties' uniqueness. The present value of future cash flows from such properties has been adjusted for the Company's assessment of risk related to the unproved properties. In assessing the risk associated with unproved properties, the Company considers the recoverability of unproved reserves that have been classified as probable and possible reserves. Probable reserves are reserves not reasonably certain or proved, yet are "more likely to be recovered than not." Possible reserves are reasonably possible but "less likely to be recovered than not." The following are the unproved properties impaired during 1998 (in thousands):

Property	Reason for Impairment	Impairment Amount
Sonora/Oakridge unproved acreage	Reserve revisions due to drilling results	$ 20,089
Offshore unproved acreage	Decline in natural gas prices	9,177
South Texas unproved acreage	Decline in natural gas prices	19,922
		$ 49,188

TRANSPORTATION, PROCESSING AND FIELD ASSETS

The Company owns and operates approximately 3,000 miles of gas gathering systems and a gas processing plant in proximity to its principal gas properties. Depreciation is calculated on the straight-line method based on estimated useful lives ranging from four to twenty years.

The Company receives fees for providing field related services. These fees are recognized as earned. Depreciation is calculated on the straight-line method based on estimated useful lives ranging from one to five years, except buildings which are being depreciated over ten to twenty-five year periods.

SECURITY ISSUANCE COSTS

Expenses associated with the issuance of the 6% Convertible Subordinated Debentures due 2007, the 8.75% Senior Subordinated Notes due 2007 and the 5 3/4% Trust Convertible Preferred Securities are included in Other Assets on the accompanying balance sheets and are being amortized on the interest method over the term of the securities.

GAS IMBALANCES

The Company uses the sales method to account for gas imbalances. Under the sales method, revenue is recognized based on cash received rather than the proportionate share of gas produced. Gas imbalances at year end 1997 and 1998 were not material.

COMPREHENSIVE INCOME

Effective January 1, 1998 the Company adopted SFAS No. 130 "Reporting Comprehensive Income" which requires disclosure of comprehensive income and its components. Comprehensive income is defined as changes in stockholders' equity from nonowner sources and, for the Company, includes net income and changes in the fair value of marketable securities. The following is a calculation of the Company's comprehensive income for the years ended December 31, 1996, 1997 and 1998.

	Year Ended December 31,		
	1996	1997	1998
Net income (loss)	$ 12,615	$ (23,332)	$(175,150)
Add: Change in unrealized gain/(loss)			
Gross	568	(322)	(78)
Tax effect	(199)	109	19
Less: Realized gain/(loss)			
Gross	(393)	(1,473)	(66)
Tax effect	138	494	15
Comprehensive income (loss)	$ 12,729	$ (24,524)	$(175,260)

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 and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

NATURE OF BUSINESS

The Company operates in an environment with many financial and operating risks, including, but not limited to, the ability to acquire additional economically recoverable oil and gas reserves, the inherent risks of the search for, development of and production of oil and gas, the ability to sell oil and gas at prices which will provide attractive rates of return, and the highly competitive nature of the industry and worldwide economic conditions. The Company's ability to expand its reserve base and diversify its operations is also dependent upon obtaining the necessary capital through operating cash flow, borrowings or the issuance of additional equity.

RECENT ACCOUNTING PRONOUNCEMENTS

In June 1998, the Financial Accounting Standards Board issued Statement of Financial Accounting Standards ("SFAS") No. 133, Accounting for Derivative Instruments and Hedging Activities, which is effective for fiscal years beginning after June 15, 1999.

SFAS No. 133 establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It also requires that an entity recognize all derivatives as either assets or liabilities on the balance sheet and measure those items at fair value. If certain conditions are met, a derivative may be specifically designated as (a) a hedge of the exposure to change in the fair value of a recognized asset or liability or an unrecognized firm commitment, (b) a hedge of the exposure to variable cash flows of a forecasted transaction or (c) a hedge of the foreign currency exposure of a net investment in a foreign operation, an unrecognized firm commitment, an available-for-sale security, or a foreign-currency-denominated forecasted transaction. The Company plans to adopt SFAS No. 133 during the first quarter of the year ended December 31, 2000 and is currently evaluating the effects of this pronouncement.

RECLASSIFICATIONS

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

(3) ACQUISITIONS

All acquisitions have been accounted for as purchases. The purchase prices were allocated to the assets acquired based on the estimated fair value of such assets and liabilities at the respective acquisition dates. The acquisitions were funded by working capital, advances under a revolving credit facility and the issuance of debt and equity securities.

In the first quarter of 1997, oil and gas properties located in West Texas, South Texas and the Gulf of Mexico (the "Cometra Properties") were acquired for $385 million. The Cometra Properties are located primarily in the Company's core operating areas and include producing oil and gas properties, leasehold acreage, gas pipelines, a 25,000 Mcf/d gas processing plant and an above-market gas contract with a utility. The utility filed an action concerning the above-market gas contract which is discussed in Note 8.

In September 1997, properties in Appalachia (the "Meadville Properties") were acquired for a purchase price of $92.5 million. The Meadville Properties are located in certain of the Company's core operating areas and included producing oil and gas properties, leasehold acreage and gas pipelines. In December 1997, the Company sold a 38% net profits interest in the properties for $36.3 million to an institutional investor. At the time the Company purchased the Meadville Properties, the Company had agreed to convey a net profits interest in the properties to an institutional investor. The institutional investor participated with the Company in the due diligence and acquisition negotiations. After the Company completed the purchase in September 1997, it subsequently conveyed the net profits interest to the institutional investor in December 1997. No gain was recognized on this transaction as the Company has retained 62% of the interest it originally owned in these properties and, as operator of the properties, has obligations with respect to them in the future. The Company does not include in its income the revenues or expenses sold in connection with the net profits interest transaction.

In December 1997, certain oil properties located in the Fuhrman-Mascho field in West Texas (the "Fuhrman-Mascho Properties") were acquired for a purchase price of $40 million. The Fuhrman-Mascho Properties included producing oil and gas properties and leasehold acreage.

In March 1998, oil and gas properties in the Powell Ranch Field in West Texas (the "Powell Ranch Properties") were acquired for a purchase price of $60 million, comprised of $54.6 million in cash and $5.4 million of Common Stock.

As described in Note 1, the Company completed the Merger for a purchase price of $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 $26.1 million and $2.7 million during the years ended December 31, 1997 and 1998, respectively.

UNAUDITED PRO FORMA FINANCIAL INFORMATION

The following table presents unaudited pro forma operating results as if certain transactions had occurred at the beginning of each period presented. In addition to the Merger, the pro forma operating results include the following transactions: (i) the sale of approximately 4 million shares of Common Stock and the application of the net proceeds therefrom, (ii) the sale of $125 million of 8.75% Senior Subordinated Notes and the application of the net proceeds therefrom, (iii) the sale of $120 million of 5 3/4% Trust Convertible Preferred Securities and the application of the net proceeds therefrom, (iv) the purchase of the Meadville Properties, (v) the purchase of the Powell Ranch Properties; and the following Domain transactions: (i) the disposition of its interest in certain natural gas properties located in Michigan, (ii) the sale of approximately 6.3 million shares of its common stock and the application of the net proceeds therefrom, and (iii), the purchase of certain net profits overriding royalty interests owned by three institutional investors. All acquisitions were accounted for as purchase transactions.

	Year ended December 31, 1997	1998
	(in thousands except per share data)	
Revenues	$ 217,690	$ 188,721
Net income (loss)	(25,290)	(177,878)
Earnings (loss) per share	(.90)	(5.11)
Earnings (loss) per share - dilutive	(.90)	(5.11)
Total assets	979,331	921,612
Stockholders' equity	281,134	133,222

The pro forma operating results have been prepared for comparative purposes only. They do not purport to present actual operating results that would have been achieved had the acquisitions and financings been made at the beginning of each period presented or to necessarily be indicative of future results of operations.

(4) IPF RECEIVABLES

At December 31, 1998, IPF had net receivables of $77.2 million. The receivables result from the Company's purchase of production payments in the form of term overriding royalty interests in exchange for an agreed upon share of revenues from identified properties until the amount invested and a specified rate of return on investment is paid in full. IPF's overriding royalty interest constitutes a property interest that serves as security for the receivables. The Company has estimated that $7.1 million of receivables at December 31, 1998 will be repaid in the next twelve months and has classified such receivables as current assets. The net outstanding receivables include an allowance for uncollectible receivables of $14 million.

(5) ASSETS HELD FOR SALE

Assets held for sale primarily consists of oil and gas properties located in south Texas and in the Gulf of Mexico. The Company has entered into agreements with an independent firm to assist it in selling these assets. The assets are recorded at the lower of cost or estimated market value of the properties as assets held for sale in the current asset section of the Consolidated Balance Sheet as of December 31, 1998. These sales are expected to be completed during 1999.

(6) INDEBTEDNESS

The Company had the following debt outstanding as of the dates shown. Interest rates at December 31, 1998 are shown parenthetically (in thousands):

	December 31, 1997	December 31, 1998
Credit Facility (6.4%)	$186,700	$365,175
Other (6.4%)	425	1,887
	187,125	367,062
Less amounts due within one year	413	55,187
Senior debt, net	$186,712	$311,875
Non-recourse debt of IPF subsidiary (7.8%)	$ -	$ 60,100
8.75% Senior Subordinated Notes due 2007	$125,000	$125,000
6% Convertible Subordinated Debentures due 2007	55,000	55,000
Subordinated debt	$180,000	$180,000

The Company maintains a $400 million revolving bank facility (the "Credit Facility"). The Credit Facility provides for a borrowing base, which is subject to semi-annual redeterminations. At December 31, 1998, the borrowing base on the facility was $385 million of which $19.8 million was available to be drawn. Interest is payable quarterly and the loan matures in February 2003. A commitment fee is paid quarterly on the undrawn balance at a rate of .25% to .375% depending upon the percentage of the borrowing base not drawn. It is the Company's policy to extend the term period of the credit facility annually. Until amounts under the Credit Facility are reduced to $300 million or the redetermined borrowing base, the interest rate will be LIBOR plus 1.75% and will increase to LIBOR plus 2.0% on May 1, 1999. When outstanding amounts are reduced to levels at or below $300 million or the redetermined borrowing base, the interest rate on the Credit Facility will return to interest at prime rate or LIBOR plus .625% to 1.125% depending on the percentage of borrowing base drawn. If amounts outstanding under the Credit Facility exceed the higher of the redetermined borrowing base or $300 million on June 30, 1999, then the Company will have 10 days to repay any excess. At December 31, 1998, the Company classified $55.2 million of borrowings under the Credit Facility as current to reflect an estimate of the amounts outstanding at December 31, 1998 that will be repaid during 1999. The weighted average interest rates on these borrowings were 7.3% and 6.7% for the years ended December 31, 1997 and 1998, respectively.

IPF has a $150 million revolving credit facility (the "IPF Facility") through which it finances its activities. The IPF Facility matures June 1, 2000 at which time all amounts owed thereunder are due and payable. The IPF Facility is secured by substantially all of IPF's assets and is non-recourse to the Company. The borrowing base under the IPF Facility is subject to redeterminations, which occur routinely during the year. On March 10, 1999, the borrowing base on the IPF Facility was $60.1 million, which did not exceed the amounts outstanding on that date. The Company is currently in the process of completing a borrowing base redetermination. Upon completion of the redetermination the Company believes the borrowing base amount will decrease slightly and that the outstanding obligations at that time will not exceed the borrowing base. The IPF Facility bears interest at prime rate or interest at LIBOR plus a margin of 1.75% to 2.25% per annum depending on the total amount outstanding. Interest expense during 1998 amounted to $1.5 million and is included in IPF expenses on the statement of income. A commitment fee is paid quarterly on the average undrawn balance at a rate of 0.375% to 0.50%. The weighted average interest rate on these borrowings was 7.8% on December 31, 1998.

The 8.75% Senior Subordinated Notes due 2007 (the "8.75% Notes") are not redeemable prior to January 15, 2002. Thereafter, the 8.75% Notes are subject to redemption at the option of the Company, in whole or in part, at redemption prices beginning at 104.375% of the principal amount and declining to 100% in 2005. The 8.75% Notes are unsecured general obligations of the Company and are subordinated to all senior debt (as defined) of the Company. The 8.75% Notes are guaranteed on a senior subordinated basis by all of the subsidiaries of the Company and each guarantor is a wholly owned subsidiary of the Company. The guarantees are full, unconditional and joint and several. Separate financial statements of each guarantor are not presented because they are included in the consolidated financial statements of the Company and management believes that their disclosure provides no additional benefits.

The 6% Convertible Subordinated Debentures Due 2007 (the "Debentures") are convertible into shares of the Company's Common Stock at the option of the holder at any time prior to maturity. The Debentures are convertible at a conversion price of $19.25 per share, subject to adjustment in certain events. Interest is payable semi-annually. The Debentures will mature in 2007 and are not redeemable prior to February 1, 2000. The Debentures are unsecured general obligations of the Company subordinated to all senior indebtedness (as defined) of the Company.

The debt agreements contain various covenants relating to net worth, working capital maintenance and financial ratio requirements. The Company is in compliance with these various covenants as of December 31, 1998. Interest paid during the years ended December 31, 1996, 1997 and 1998 totaled $7.5 million, $18.2 million and $39.6 million, respectively.

Maturities of senior indebtedness and the IPF Facility as of December 31, 1998 were as follows (in thousands):

1999	$ 55,187
2000	60,100
2001	--
2002	--
2003	311,875
Remainder	--
	$427,162

(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 the short maturity of these instruments. The Company believes that the carrying value of its borrowings under the Credit and IPF Facilities (collectively "the Bank Facilities") approximate their fair value as they bear interest at rates indexed to LIBOR. In connection with the Merger, the IPF receivables were adjusted to what the Company estimates to have been their fair values at that time. The Company's receivables are concentrated in the oil and gas industry. The Company does not view such a concentration as an unusual credit risk. Excluding IPF's valuation allowances, the Company had recorded an allowance for doubtful accounts of $539,000 and $782,000 at December 31, 1997 and 1998, respectively.

A portion of the Company's crude oil and natural gas sales are periodically hedged against price risks through the use of futures, option or swap contracts. The gains and losses on these instruments are included in the valuation of the production being hedged in the contract month and are included as an adjustment to oil and gas revenue. The Company also manages interest rate risk on its credit facility through the use of interest rate swap agreements. Gains and losses on interest rate swap agreements are included as an adjustment to interest expense.

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

	December 31, 1997		December 31, 1998	
	(In thousands)			
	Book Value	Fair Value	Book Value	Fair Value
Cash and equivalents	$ 9,725	$ 9,725	$ 10,954	$ 10,954
Marketable securities	5,407	5,777	2,966	3,258
Long-term debt	(367,125)	(367,125)	(607,162)	(607,162)
Commodity swaps	--	1,071	--	45
Interest rate swaps	--	73	--	(361)

At December 31, 1998, the Company had open contracts for gas price swaps of 6.4 Bcf. The swap contracts are designed to set average prices ranging from $1.90 to $2.64 per Mcf. 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 gain of approximately $44,500 at December 31, 1998. These contracts expire monthly through October 1999. The gains or losses on the Company's hedging transactions are determined as the difference between the contract price and the reference price, generally closing prices on the NYMEX. The resulting transaction gains and losses are determined monthly and are included in oil and gas revenues in the period the hedged production or inventory is sold. Net gains or (losses) relating to these derivatives for the years ended December 31, 1996, 1997 and 1998 approximated $(.7) million, $(.9) million and $3.1 million respectively.

Interest rate swap agreements, which are used by the Company in the management of interest rate exposure, are accounted for on the accrual basis. Income and expense resulting from these agreements are recorded in the same category as interest expense arising from the related liability. Amounts to be paid or received under interest rate swap agreements are recognized as an adjustment to expense in the periods in which they accrue. At December 31, 1998, the Company had $100 million of borrowings subject to five interest rate swap agreements at rates of 5.71%, 5.59%, 5.35%, 4.82% and 5.64% through September 1999, October 1999, January 2000, September 2000 and October 2000 respectively. The interest rate swaps may be extended at the counterparties' option for two years. The agreements require that the Company pay the counterparty interest at the above fixed swap rates and requires the counterparty to pay the Company interest at the 30-day LIBOR rate. The closing 30-day LIBOR rate on December 31, 1998 was 5.06%. The fair value of the interest rate swap agreements at December 31, 1998, is based upon current quotes for equivalent agreements. As discussed in Note 6, the Company's Bank Facilities are based on LIBOR plus Applicable Margin (as defined).

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

(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 July 1997, a gas utility filed an action in the State District Court of Texas. In the lawsuit, the gas utility asserted a breach of contract claim arising out of a gas purchase contract. Under the gas utility's interpretation of the contract, it sought, as damages, the reimbursement of the difference between the above-market contract price it paid and market price on a portion of the gas it has taken beginning in July 1997. In May 1998, the court granted a partial summary judgment on the contract interpretation issue in favor of the gas utility. The summary judgment allows the utility to take or pay for a limited volume of gas defined in the contract as the "contract volume" at the contract price. In October 1998, the gas utility dropped its damages claim and the state district court signed a final judgment in this case. Range has appealed to reverse the final judgment. Range believes, under its interpretation, the utility is required to take all legally produced gas at the contract price. If Range wins the appeal, the summary judgment will be reversed. The court of appeals may either declare the contract's interpretation in Range's favor or declare that the contract provisions at issue are ambiguous. In either event, the case will be remanded to the trial court for a factual determination of the parties' obligations and/or remedies under the contract. If Range loses the appeal, the summary judgment will be affirmed and no further court action will be required.

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 money damages. On September 3, 1998, the parties executed a Memorandum of Understanding (the "MOU"), which represents a settlement in principle of the litigation. 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 also agreed to pay any court-awarded attorneys' fees and expenses of the plaintiffs' counsel in an amount not to exceed $290,000. The settlement in principle is subject to court approval and certain other conditions that have not been satisfied.

The Company leases certain office space and equipment under cancelable and non-cancelable leases, most of which expire within 10 years and may be renewed by the Company. Rent expense under such arrangements totaled $406,000, $628,000 and $595,000 in 1996, 1997 and 1998, respectively. Future minimum rental commitments under non-cancelable leases are as follows (in thousands):

1999.............................	$ 1,000
2000.............................	899
2001.............................	778
2002.............................	569
2003.............................	195
2004 and thereafter...............	195
	$ 3,636

(9) EQUITY SECURITIES AND CONVERTIBLE PREFERRED SECURITIES

On October 16, 1997, the Company, through a newly-formed affiliate Lomak Financing Trust (the "Trust"), completed the issuance of $120 million of 5 3/4% trust convertible preferred securities (the "Convertible Preferred Securities"). The Trust issued 2,400,000 shares of the Convertible Preferred Securities at $50 per share. Each Convertible Preferred Security 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 Range (the "Junior Debentures"). In turn, Range used the net proceeds from the issuance of the Junior Convertible Debentures to repay a portion of its credit facility. The sole assets of the Trust are the Junior Debentures. The Junior Debentures and the related Convertible Preferred

Securities mature on November 1, 2027. Range and the Trust may redeem the Junior Debentures and the Convertible Preferred Securities, respectively, in whole or in part, on or after November 4, 2000. For the first twelve months thereafter, redemptions may be made at 104.025% of the principal amount. This premium declines proportionally every twelve months until November 1, 2007, when the redemption price becomes fixed at 100% of the principal amount. If Range redeems any Junior Debentures prior to the scheduled maturity date, the Trust must redeem Convertible Preferred Securities having an aggregate liquidation amount equal to the aggregate principal amount of the Junior Debentures so redeemed.

Range has guaranteed the payments of distributions and other payments on the Convertible Preferred Securities only if and to the extent that 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 guarantee of amounts due on the Convertible Preferred Securities.

Range owns all the common securities of the Trust. As such, the accounts of the Trust have been included in Range's consolidated financial statements after appropriate eliminations of intercompany balances. The distributions on the Convertible Preferred Securities have been recorded as a charge to interest expense on Range's consolidated statements of income, and such distributions are deductible by Range for income tax purposes.

In March 1997, the Company sold 4 million shares of common stock in a public offering for $69 million. Warrants to acquire 20,000 shares of common stock at a price of $12.88 per share were exercised in May 1997. At December 31, 1998 the Company had no outstanding warrants.

In November 1995, the Company issued 1,150,000 shares of $2.03 convertible exchangeable preferred stock (the "$2.03 Preferred Stock") for $28.8 million. The $2.03 Preferred Stock is convertible into the Company's common stock at a conversion price of $9.50 per share, subject to adjustment in certain events. The $2.03 Preferred Stock is redeemable, at the option of the Company, at any time on or after November 1, 1998, at redemption prices beginning at 105%. At the option of the Company, the $2.03 Preferred Stock is exchangeable into 8-1/8% Convertible Subordinated Notes due 2005. The notes would be subject to the same redemption and conversion terms as the $2.03 Preferred Stock.

(10) STOCK OPTION AND PURCHASE PLAN

The Company has four stock option plans as well as a stock purchase plan. Two of the stock option plans were adopted as a result of the Merger. Information with respect to these stock option plans is summarized as follows:

			Plans adopted via the Merger		
	Option Plan	Director's Plan	Option Plan	Director's Plan	Total
Outstanding at December 31, 1997:	1,507,692	108,000	--	--	1,615,692
Granted	828,395	32,000	--	--	860,395
Adopted in Merger	--	--	1,143,665	19,340	1,163,005
Exercised	(54,610)	--	(49,155)	--	(103,765)
Expired/Cancelled	(238,720)	--	(155,534)	--	(394,254)
Outstanding at December 31, 1998:	2,042,757	140,000	938,976	19,340	3,141,073

Range maintains a stock option plan (the "Option Plan") which authorizes the grant of options on up to 3.0 million shares of Common Stock. However, no new options may be granted which would result in there being outstanding aggregate options exceeding 10% of common shares outstanding plus those shares issuable under convertible securities. Under the Option Plan, incentive and non-qualified options may be issued to officers, key employees and consultants. The Option Plan is administered by the

Compensation Committee of the Board. All options issued under the Option Plan before September 1998 vest 30% after one year, 60% after two years and 100% after three years and options issued after that date vest 25% per year beginning one year after the grant date. During the year ended December 31, 1998, options covering 54,610 shares were exercised at prices ranging from $5.12 to $10.50 per share. At December 31, 1998, there were 903,442 options exercisable at prices ranging from $3.375 to $17.75 per share.

In 1994, the stockholders approved the 1994 Outside Directors Stock Option Plan (the "Directors Plan"). Only Directors who are not employees of the Company are eligible under the Directors Plan. The Directors Plan covers a maximum of 200,000 shares. At December 31, 1998, there were outstanding 72,800 options which were exercisable at prices ranging from $7.75 to $16.88 per share.

In connection with the Merger, Range adopted the Second Amended and Restated 1996 Stock Purchase and Option Plan for Key Employees of Domain Energy Corporation and Affiliates (the "Domain Option Plan") and the Domain Energy Corporation 1997 Stock Option Plan for Nonemployee Directors (the "Domain Director Plan"). Subsequent to the Merger, no new options will be granted under the Domain Option and Director Plans and existing options are exercisable into shares of Range Common Stock. During the year ended December 31, 1998 options covering 49,155 shares were exercised at prices ranging from $0.01 to $3.46 per share. At December 31, 1998, 469,014 options were currently exercisable under the Domain Option Plan at $3.46 to $11.70 per share. The remaining 469,962 options are currently exercisable at an exercise price of $0.01 per share. At December 31, 1998, options totaling 19,340 shares were outstanding and exercisable under the Domain Director Plan at $11.77 per share.

In June 1997, the stockholders approved the 1997 Stock Purchase Plan (the "1997 Plan") which authorizes the sale of up to 500,000 shares of common stock to officers, directors, key employees and consultants. Under the Plan, the right to purchase shares at prices ranging from 50% to 85% of market value may be granted. The Company previously had stock purchase plans which covered 833,333 shares. The previous stock purchase plans have been terminated. The plans are administered by the Compensation Committee of the Board. During the year ended December 31, 1998, officers, key employees and outside directors purchased 306,141 registered common shares from the Company for total consideration of $1.6 million. From inception through December 31, 1998, a total of 759,141 unregistered shares had been sold through stock purchase plans, for a total consideration of approximately $5.3 million.

The Company has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock Based Compensation." Accordingly, no compensation cost has been recognized for the stock option plans. Had compensation cost for the Corporation's stock option plans been determined based on the fair value at the grant date for awards in 1996, 1997 and 1998 consistent with the provisions of SFAS No. 123, the Company's net earnings and earnings per share would have been reduced to the pro forma amounts indicated below:

	1996	1997	1998
	(in thousands, except per share data)		
Net earnings (loss)-- as reported	$ 12,615	$ (23,332)	$ (175,150)
Earnings (loss) per share-- as reported	$ 0.71	$ (1.31)	$ (6.82)
Earnings (loss) per share dilutive-- as reported	$ 0.69	$ (1.31)	$ (6.82)
Net earnings (loss)-- pro forma	$ 12,262	$ (24,563)	$ (176,083)
Earnings (loss) per share--pro forma	$ 0.68	$ (1.37)	$ (6.86)
Earnings (loss) per share dilutive--pro forma	$ 0.66	$ (1.37)	$ (6.86)

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 1996, 1997 and 1998, respectively: dividend yields of $.06, $.10 and $.12 per share; expected volatility factors of .41, .46 and .79 risk-free interest rates of 6.0%; 6.5% and 4.75%; and a average expected life of 3 to 5 years.

(11) BENEFIT PLAN

The Company maintains a 401(K) Plan for the benefit of its employees. The Plan permits employees to make contributions on a pre-tax salary reduction basis. The Company makes discretionary contributions to the Plan. Company contributions for 1996, 1997 and 1998 were $548,000, $701,000 and $678,000 respectively. The 1997 and 1998 contributions were made with Range common stock, which was valued at fair market value.

(12) INCOME TAXES

Federal income tax provision (benefit) was $6.8 million, $(11.8) million and $(54.7) million for the years 1996, 1997 and 1998, respectively. The current portion of the income tax provision 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:

	1996	1997	1998
Statutory tax rate	34%	(34)%	(34)%
Valuation allowance	--	--	10
Other	1	--	--
Effective tax rate..	35%	(34)%	(24)%
Income taxes paid...	$ 590,000	$ 1,216,000	$ 36,000

The Company follows FASB Statement No. 109, "Accounting for Income Taxes". Under Statement 109, the liability method is used in accounting for income 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 laws 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, 1997	December 31, 1998
Deferred tax liabilities:		
Depreciation	$ 38,305	$ 30,232
Deferred tax assets:		
Net operating loss carryforward	$ 9,268	$ 51,810
Percentage depletion carryforward	2,753	2,753
AMT credits and other	685	685
Total deferred tax assets	12,706	55,248
Valuation allowance for deferred tax assets	(40)	(25,016)
Net deferred tax assets	$ 12,666	$ 30,232
Net deferred tax liabilities	$ 25,639	$ --

Utilization of the deferred tax asset of $55.2 million is dependent on future taxable profits being in excess of profits arising from existing taxable temporary differences. The Company has established a

$25 million valuation allowance and has written down to zero its net deferred tax assets at December 31, 1998. 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, $25 million of the valuation allowance will reduce the Company's future income tax expense.

The Company has entered into several business combinations accounted for as purchases. In connection with these transactions, deferred tax assets and liabilities of $7.7 million and $25.9 million respectively, were recorded. In 1997 the Company acquired Arrow Operating Company accounted for as a tax free business combination accounted for as a purchase. A net deferred tax liability of $12.4 million was recorded in the transaction. In 1998 the Company acquired Domain Energy Corporation in a taxable business combination accounted for as a purchase. A net deferred tax liability of $29 million was recorded in the transaction.

As a result of the Company's issuance of equity and convertible debt securities, it experienced a change in control during 1988 as defined by Section 382 of the Internal Revenue Code. The change in control and the Merger have placed limitations to the utilization of net operating loss carryovers. At December 31, 1998, the Company had available for federal income tax reporting purposes net operating loss carryovers of approximately $131 million which are subject to annual limitations as to their utilization and otherwise expire between 1999 and 2013, if unused. The Company has alternative minimum tax net operating loss carryovers of $116 million which are subject to annual limitations as to their utilization and otherwise expire from 1999 to 2013 if unused. The Company has statutory depletion carryover of approximately $4 million and an alternative minimum tax credit carryover of approximately $911,000. The statutory depletion carryover and alternative minimum tax credit carryover are not subject to limitation or expiration.

(13) BUSINESS RESTRUCTURING COSTS

In the fourth quarter of 1998, the Company initiated a restructuring plan to reduce costs and improve operating efficiencies. The restructuring plan included actions by the Company to close its Midland, Texas field office, eliminate certain geological and exploration positions, cancel certain exploration and drilling obligations, as well as consolidate certain administrative functions at the remaining locations. In connection with the restructuring plan, 54 employees have been terminated. The terminated employees were comprised as follows: 33 in operations; 11 in exploration; 3 in Midland office; 3 in gas marketing; 2 in IPF; and 2 in investor relations. These employees were associated with operations that have been consolidated or eliminated in response to the depressed energy price environment. Estimated employee termination costs of $2.1 million have been accrued in 1998. Of the total number of employees affected, 42 were terminated in 1998.

In addition to the costs of terminating employees, 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 $.6 million for estimated costs to exit lease and other contractual commitments and an additional $.4 million relating to costs associated with the closing of the Midland, Texas office, which was deemed to be uneconomical. The $.4 million of associated costs consisted of $.1 million of costs to exit the office lease and $.3 million of costs to exit two exploration agreements. The Midland office was responsible primarily for the operation of a portion of the Company's Permian assets. The operation of these assets has been consolidated in the Company's Fort Worth, Texas office. At December 31, 1998, $2.7 million was accrued in connection with the restructuring plan. This plan is anticipated to be completed by the third quarter of 1999.

(14) EARNINGS PER COMMON SHARE

The following table sets forth the computation of earnings per common share and earnings per common share - assuming dilution (in thousands):

	1996	1997	1998
Numerator:			
Net income (loss)	$ 12,615	$ (23,332)	$(175,150)
Preferred stock dividends	(2,454)	(2,334)	(2,334)
Numerator for earnings per common share	10,161	(25,666)	(177,484)
Effect of dilutive securities:			
Preferred stock dividends	--	--	--
Numerator for earnings per common Share - assuming dilution	$ 10,161	$ (25,666)	$(177,484)
Denominator:			
Denominator for earnings per common Share - weighted average shares	14,334	19,641	26,008
Effect of dilutive securities:			
Employee stock options	464	--	--
Warrants	14	--	--
Dilutive potential common shares	478	--	--
Denominator for diluted earnings per share Adjusted weighted-average shares and Assumed conversions	14,812	19,641	26,008
Earnings (loss) per common share	$ .71	$ (1.31)	$ (6.82)
Earnings (loss) per common Share - assuming dilution	$ .69	$ (1.31)	$ (6.82)

For additional disclosure regarding the Company's Debentures, the 7 1/2% Preferred Stock and the $2.03 Preferred Stock, see Notes 6, and 9 respectively. The Debentures were outstanding during 1996, 1997 and 1998 but were not included in the computation of diluted earnings per share because the conversion price was greater than the average market price of common shares and, therefore, the effect would be antidilutive. The 7 1/2% Preferred Stock was converted into 576,945 additional shares of common stock during 1996. The 576,945 additional shares were not included in the computation of diluted earnings per share because the effect was antidilutive. The $2.03 Preferred Stock was outstanding during 1996, 1997 and 1998 and was convertible into 3,026,316 of additional shares of common stock. The 3,026,316 additional shares were not included in the computation of diluted earnings per share because the conversion price was greater than the average market price of common shares and, therefore, the effect would be antidilutive. There were stock options outstanding during 1997 which were exercisable, resulting in 642,720 additional shares under the treasury method of accounting for common stock equivalents. These were stock options outstanding during 1998 which were exercisable, resulting in 718,279 additional shares for common stock equivalents. These additional shares were not included in the 1997 or 1998 computations of diluted earnings per share because the effect was antidilutive.

(15) MAJOR CUSTOMERS

The Company markets its oil and gas production on a competitive basis. The type of contract under which gas production is sold varies but can generally be grouped into three categories: (a) life-of-the-well; (b) long-term (1 year or longer); and (c) short-term contracts which may have a primary term of one year, but which are cancelable at either party's discretion in 30-120 days. Approximately 71% of the Company's gas production is currently sold under market sensitive contracts which do not contain floor price provisions. For the year ended December 31, 1998, one customer accounted for 14% of the Company's total oil and gas revenues. Management believes that the loss of any one customer would not have a material adverse effect on the operations of the Company. Oil is sold on a basis such that the purchaser can be changed on 30 days notice. The price received is generally equal to a posted price set by the major purchasers in the area. The Company sells to oil purchasers on a basis of price and service.

(16) OIL AND GAS ACTIVITIES

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

	Year Ended December 31,		
	1996	1997	1998
	(in thousands)		
Oil and gas properties:			
Subject to depletion	$ 259,681	$ 674,067	$ 859,911
Not subject to depletion	22,838	111,156	75,911
Total	282,519	785,223	935,822
Accumulated depletion	(53,102)	(161,416)	(273,723)
Net oil and gas properties	$ 229,417	$ 623,807	$ 662,099
Costs incurred:			
Acquisition	$ 63,579	$ 448,822	$ 286,974
Development	12,536	56,430	71,793
Exploration	2,025	2,375	9,756
Total costs incurred	$ 78,140	$ 507,627	$ 368,523

(17) UNAUDITED SUPPLEMENTAL RESERVE 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 (Bbls)	Natural Gas (Mcf)
	(in thousands)	
Balance, December 31, 1995	10,863	232,887
Revisions	280	(7,545)
Extensions, discoveries and additions	952	16,696
Purchases	3,884	86,022
Sales	(236)	(11,235)
Production	(1,068)	(21,231)
Balance, December 31, 1996	14,675	295,594
Revisions	(2,603)	(70,763)
Extensions, discoveries and additions	1,664	55,324
Purchases	18,541	339,447
Sales	(709)	(6,775)
Production	(1,794)	(38,409)
Balance, December 31, 1997	29,774	574,418
Revisions	(14,195)	(76,728)
Extensions, discoveries and additions	2,121	57,261
Purchases	15,332	140,120
Sales	(3,248)	(16,561)
Production	(2,655)	(45,193)
Balance, December 31, 1998	27,129	633,317

PROVED DEVELOPED RESERVES

	Crude Oil	Natural Gas
December 31, 1996	10,703	207,601
December 31, 1997	14,971	369,786
December 31, 1998	19,649	436,062

The revisions which occurred during 1998 include 13,126 Mbbl of oil and 49,004 Mmcf of gas which became uneconomic due to lower commodity prices at December 31, 1998 as compared to December 31, 1997. The commodity prices used to estimate the December 31, 1998 reserve information were $10.25 per barrel for oil, $6.61 per barrel for natural gas liquids and $2.34 per Mcf for gas. The average prices at December 31, 1997 were $16.00 per barrel for oil, $10.27 per barrel for natural gas liquids and $2.79 per Mcf for gas.

The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves" (Standardized Measure) is a disclosure requirement under Statement of Financial Accounting Standards 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		
	1996	1997	1998
	(in thousands)		
Future cash inflows	$ 1,393,338	$ 2,037,357	$ 1,744,653
Future costs:			
Production	(365,753)	(512,657)	(513,119)
Development	(86,192)	(248,553)	(211,236)
Future net cash flows	941,393	1,276,147	1,020,298
Income taxes	(271,023)	(280,189)	(104,500)
Total undiscounted future net cash flows	670,370	995,958	915,798
10% discount factor	(319,481)	(485,258)	(398,703)
Standardized measure	$ 350,889	$ 510,700	$ 517,095

CHANGES IN STANDARDIZED MEASURE

	For the year ended December 31		
	1996	1997	1998
	(in thousands)		
Standardized measure, beginning of year	$ 174,050	$ 350,889	$ 510,700
Revisions:			
Prices	151,508	(210,429)	(138,985)
Quantities	(6,762)	(29,409)	(112,012)
Estimated future development cost	(2,971)	(37,788)	26,465
Accretion of discount	22,924	49,217	63,233
Income taxes	(86,095)	10,360	88,222
Net revisions	78,604	(218,049)	(73,007)
Purchases	125,871	460,753	134,186
Extensions, discoveries and additions .	22,816	55,751	35,169
Production	(43,598)	(93,865)	(87,668)
Sales	(6,854)	(14,406)	(26,197)
Changes in timing and other	--	(30,373)	23,982
Standardized measure, end of year	$ 350,889	$ 510,700	$ 517,095

RANGE RESOURCES CORPORATION

INDEX TO EXHIBITS

(Item 14[a 3])

Exhibit No	Description
3.1(a)	Certificate of Incorporation of Lomak dated March 24, 1980 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
3.1(b)	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(c)	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(d)	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(e)	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(f)	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(g)	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(h)	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(i)	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(j)	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(k)	Certificate of Amendment of Certificate of Incorporation dated August 25, 1998 (incorporated by reference to the Company's Registration Statement (No. 333-62439)).
3.2	By-Laws of the Company (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
4	Specimen certificate of Lomak Petroleum, Inc. (incorporated by reference to the Company's Registration Statement (No. 333-20257)).
4.4	Certificate of Trust of Lomak Financing Trust (incorporated by reference to the Company's Registration Statement (No. 333-43823)).
4.5	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)).
4.6	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)).
4.7	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)).

4.8	Form of 5 3/4% Preferred Convertible Securities (included in Exhibit 4.5 above).
4.9	Form of 5 3/4% Convertible Junior Subordinated Debentures (included in Exhibit 4.7 above).
4.10	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)).
4.11	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)).
4.12	Purchase and Sale Agreement between Cometra Energy, L.P. and Cometra Production Company, L.P., as seller, and Lomak Petroleum, Inc., as buyer, dated December 31, 1996, including First Amendment to Purchase and Sale Agreement, dated January 10, 1997 (incorporated by reference to the Company's Registration Statement (No. 333-20257)).
4.13	Purchase and Sale Agreement between Rockland, L.P., as seller, and Lomak Petroleum, Inc., as buyer, dated December 31, 1996 (incorporated by reference on the Company's Registration Statement (No. 333-20257)).
4.14	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)).
4.15	Purchase and Sale Agreement dated as of September 8, 1997 by and among Cabot Oil & Gas Corporation, Cranberry Pipeline Corporation, Big Sandy Gas Company, and Lomak Petroleum, Inc. (incorporated by reference to the Company's Form 10-K dated March 20, 1998).
4.16	Agreement and Plan of Reorganization dated December 5, 1997 between Arrow Operating Company, Kelly W. Hoffman and L .S. Decker and Lomak Petroleum, Inc. (incorporated by reference to the Company's Registration Statement (No. 333-43823))
4.17	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).
10.1(a)	Incentive and Non-Qualified Stock Option Plan dated March 13, 1989 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
10.1(b)	Advisory Agreement dated September 29, 1988 between Lomak and SOCO (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
10.1(c)	401(k) Plan Document and Trust Agreement effective January 1, 1989 (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
10.1(d)	1989 Stock Purchase Plan (incorporated by reference to the Company's Registration Statement (No. 33-31558)).
10.1(e)	Form of Directors Indemnification Agreement (incorporated by reference to the Company's Registration Statement (No. 333-47544)).
10.1(f)	1994 Outside Directors Stock Option Plan (incorporated by reference to the Company's Registration Statement (No. 33-47544)).
10.1(g)	1994 Stock Option Plan (incorporated by reference to the Company's Registration Statement (No. 33-47544)).
10.1(h)	$400,000,000 Credit Agreement Among Lomak Petroleum, Inc., as Borrower, and the Several Lenders from Time to Time parties Hereto, including Bank One, Texas, N.A. as Administrative Agent, The Chase Manhattan Bank, as Syndication Agent, and Nationsbank of Texas, N.A., as Documentation Agent (incorporated by reference to the

Company's Form 10-K dated February 7, 1997).

10.1(i)	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)).
10.1(j)	Amendment to the Lomak Petroleum, Inc., 1989 Stock Purchase Plan, as amended (incorporated by reference to the Company's Registration Statement (No. 333-44821)).
10.1(k)	1997 Stock Purchase Plan (incorporated by reference to the Company's Registration Statement (No. 333-44821)).
10.1(l)	1997 Stock Purchase Plan, as amended (incorporated by reference to the Company's Registration Statement (No. 333-44821)).
10.1(m)**	Fourth Amendment to $400,000,000 Credit Agreement dated January 27, 1999
10.1(n)	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)).
10.1(o)	Domain Energy Corporation 1997 Stock Option Plan for Nonemployee Directors (incorporated by reference to the Company's Registration Statement (No. 333-62439)).
10.1(p)**	Employment Agreement, dated August 25, 1998, between the Company and Michael V. Ronca.
21*	Subsidiaries of the Registrant.
23.1*	Consent of Independent Public Accountants.
23.2*	Consent of Netherland, Sewell & Associates, Inc., independent consulting petroleum engineers.
23.3*	Consent of H.J. Gruy and Associates, Inc., independent consulting petroleum engineers.
23.4*	Consent of DeGoyler and MacNaughton, independent consulting petroleum engineers.
23.5*	Consent of Wright & Company, Inc., independent consulting petroleum engineers.
23.6*	Consent of Clay, Holt & Klammer, independent consulting petroleum engineers.
27**	Financial Data Schedule.

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* Filed herewith.

** Previously filed.

EXHIBIT 21

RANGE RESOURCES CORPORATION

SUBSIDIARIES OF REGISTRANT

Name	Jurisdiction of Incorporation	Percentage of Voting Securities Owned by Immediate Parent
Range Operating Company	Ohio	100%
Range Production Company	Delaware	100%
Buffalo Oilfield Services, Inc.	Ohio	100%
Range Energy Services Company	Delaware	100%
Range Resources Development Company	Delaware	100%
Range Energy I, Inc.	Delaware	100%
Range Gathering & Processing Company	Delaware	100%
Range Gas Company	Delaware	100%
Lomak Financing Trust	Delaware	100%
RRC Operating Company	Ohio	100%
Range Energy Finance Corporation	Delaware	100%
Range Energy Ventures Corporation	Delaware	100%
Gulfstar Energy, Inc.	Delaware	100%
Gulfstar Seismic, Inc.	Delaware	100%
Domain Energy International Corporation	British Virgin Islands	100%

EXHIBIT 23.1

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our report on the consolidated financial statements of Range Resources Corporation for the year ended December 31, 1998, included in this Form 10-K, into the Company's previously filed Registration Statements on Form S-1 File No. 333-08211, Form S-3 File No. 333-23955, Form S-8 File No. 10719, Form S-8 File No. 33-66322, Form S-3 File No. 33-64303, Form S-3 File No. 333-20257, Form S-3 File No. 333-43823, Form S-8 File No. 333-44821, Form S-3 File No. 333 51503, Form S-4 File No. 333-57639 and Form S-8 File No. 333-62439.

ARTHUR ANDERSEN LLP

Cleveland, Ohio
September 16, 1999

Exhibit 23.2

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGIST

We hereby consent to the reference to our firm under the caption "Proved Reserves" in this Annual Report on Form 10-K/A of Range Resources Corporation.

NETHERLAND, SEWELL & ASSOCIATES, INC.

Dallas, Texas
September 16, 1999

Exhibit 23.3

CONSENT OF H. J. GRUY AND ASSOCIATES, INC.

We hereby consent to the use of the name H.J. Gruy and Associates, Inc. And of references to H.J. Gruy and Associates, Inc. And to the inclusion of and references to our report dated February 25, 1999, prepared for Range Resources Corporation in the Range Resources Corporation Annual Report on Form 10-K/A for the year ended December 31, 1998.

H.J. GRUY AND ASSOCIATES, INC.

September 16, 1999
Houston, Texas

Exhibit 23.4

CONSENT OF DEGOLYER AND MACNAUGHTON

We hereby consent to the reference to our firm under the caption "Proved Reserves" in the Annual Report on Form 10-K/A of Range Resources Corporation.

DEGOLYER AND MACNAUGHTON

Dallas, Texas
September 16, 1999

Exhibit 23.5

CONSENT OF INDEPENDENT PETROLEUM CONSULTANTS

Wright & Company, Inc., (Wright) hereby consents to the reference to our name in the Annual Report on Form 10-K/A of Range Resources Corporation (the Company) for the year ended December 31, 1998.

WRIGHT AND COMPANY, INC.

Wright & Company, Inc.
Brentwood, TN
September 16, 1999

Exhibit 23.6

CONSENT OF INDEPENDENT PETROLEUM CONSULTANTS

We hereby consent to the reference to our firm under the caption "Proved Reserves" in this Annual Report on Form 10-K/A of Range Resources Corporation.

CLAY HOLT & KLAMMER

Pittsburgh, PA
September 16, 1999