RANGE RESOURCES

ANNUAL REPORT 2002

RANGE RESOURCES COMPANY PROFILE

OVERVIEW

Headquarters ..... Fort Worth, Texas
Assets at Year-end ..... $658 Million
Equity Market Capitalization at Year-end ..... $297 Million
Divisions ..... Southwest, Gulf Coast, Appalachia

PRODUCTION

Natural Gas ..... 112,592 mcf per day (76%)
Crude Oil and Liquids ..... 6,245 bbls per day (24%)
Total ..... 150,061 mcfe per day (100%)

OPERATIONS

Producing Wells ..... 10,909 gross/5,395 net
Percent Operated 90%
Drilling Expenditures ..... $95 million
Drilling ..... 328 gross/178.6 net wells
Success Ratio 95%

PROVEN RESERVES/ACREAGE AT YEAR-END

Natural Gas ..... 440 Bcf (76%)
Crude Oil and Liquids ..... 23 Mmbbls (24%)
Total ..... 578 Bcfe (100%)
Pretax SEC PV10 Value ..... $965 million
Reserve Life Index ..... 10.6 years
Proven Development Projects ..... 2,047 gross/1,039 net
Undeveloped Acreage ..... 676,530 gross/328,261 net

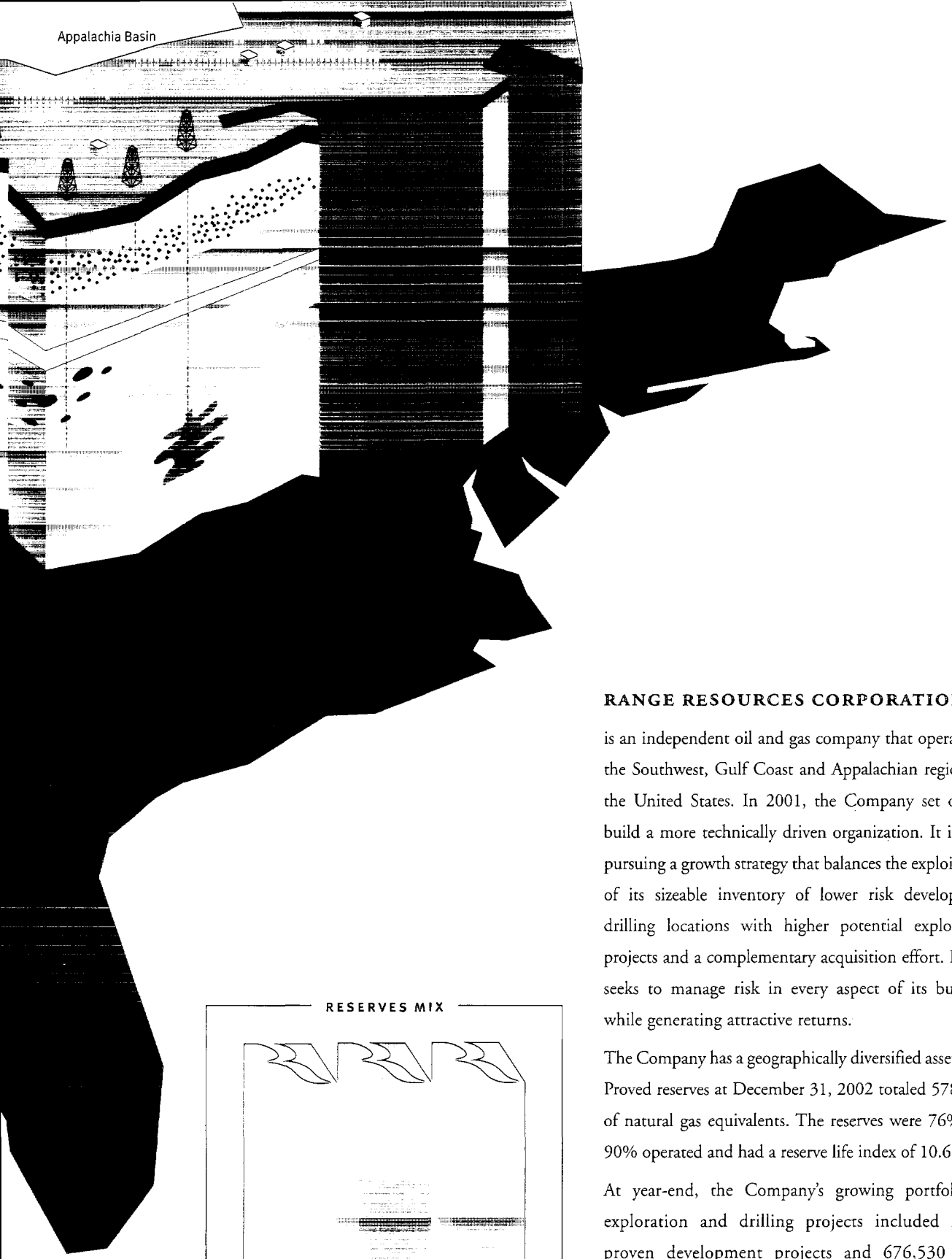
STOCK INFORMATION

NYSE Symbol ..... RRC
Stock Price High $5.96
Stock Price Low $4.03
Average Daily Volume 142,554
Shares Outstanding at Year-end ..... 55.0 million

FINANCIAL HIGHLIGHTS (MILLIONS EXCEPT PER SHARE DATA)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Revenue	$8.6	$12.1	$26.6	$41.2	$75.3	$145.4	$151.7	$193.0	$184.8	$219.4	$195.3
Operating Margin	6.3	8.4	18.0	28.6	51.3	106.3	103.3	110.2	137.8	168.9	154.0
Net Income (Loss)	0.7	1.4	2.6	4.4	12.6	(23.3)	(181.3)	(23.5)	36.6	17.7	25.8
Earnings per Share	0.09	0.19	0.25	0.31	0.71	(1.31)	(7.11)	(0.71)	0.96	0.36	0.47
Cash Flow[a]	3.8	6.0	13.2	21.5	42.5	81.8	56.0	59.9	93.7	131.8	118.0
Shares Outstanding	4.8	8.3	9.8	13.3	14.8	21.1	35.9	37.9	49.2	52.6	55.0
Total Debt	13.1	31.1	62.6	83.1	116.8	487.1	727.3	576.6	458.1	392.2	368.0
Equity	9.5	32.3	43.2	99.2	117.5	197.0	125.7	103.2	259.9	235.6	206.1
Total Assets	28.3	76.3	141.8	214.8	282.5	758.8	914.0	732.2	671.8	682.5	655.6

(a) Cash flow from operations before changes in working capital plus exploration expense.

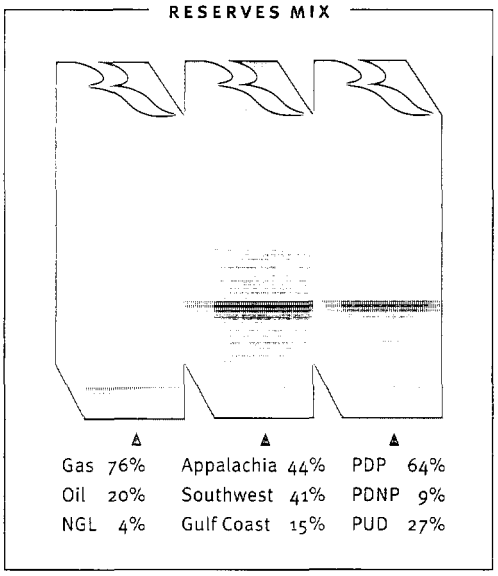


RANGE RESOURCES CORPORATION

is an independent oil and gas company that operates in the Southwest, Gulf Coast and Appalachian regions of the United States. In 2001, the Company set out to build a more technically driven organization. It is now pursuing a growth strategy that balances the exploitation of its sizeable inventory of lower risk development drilling locations with higher potential exploration projects and a complementary acquisition effort. Range seeks to manage risk in every aspect of its business while generating attractive returns.

The Company has a geographically diversified asset base. Proved reserves at December 31, 2002 totaled 578 Bcfe of natural gas equivalents. The reserves were 76% gas, 90% operated and had a reserve life index of 10.6 years.

At year-end, the Company's growing portfolio of exploration and drilling projects included 2,047 proven development projects and 676,530 gross (328,261 net) acres of undeveloped leasehold. In 2002, 222% of production was replaced at an average cost of $0.92 per mcfe. Range's common stock is listed on the New York Stock Exchange under the symbol "RRC."

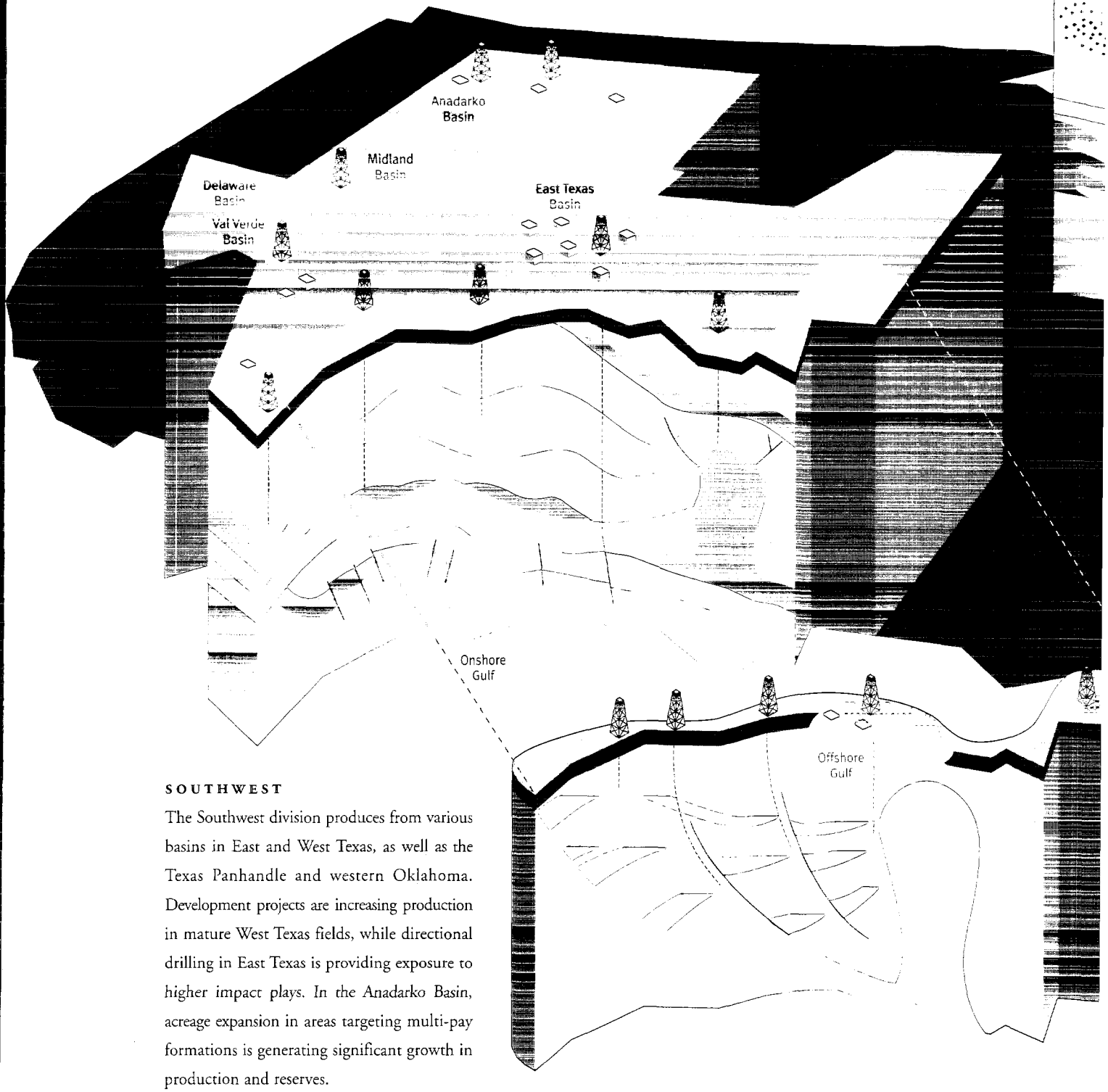


drilling areas | areas of exploration | areas of production

AREAS OF OPERATION

APPALACHIA

The Appalachia division operates in shallow plays and deeper formations in the Appalachian and Michigan basins of the northeastern United States. The division drilled 242 wells in 2002, achieving a 95% success rate. With a leasehold position covering 1,130,237 (518,104 net) acres, the division has a significant number of drilling opportunities.



SOUTHWEST

The Southwest division produces from various basins in East and West Texas, as well as the Texas Panhandle and western Oklahoma. Development projects are increasing production in mature West Texas fields, while directional drilling in East Texas is providing exposure to higher impact plays. In the Anadarko Basin, acreage expansion in areas targeting multi-pay formations is generating significant growth in production and reserves.

GULF COAST

The Gulf Coast division operates onshore in Texas, Louisiana and Mississippi, as wel as offshore, with interests in 40 platforms located in the shallow waters of the Gulf o Mexico. By owning interests in higher risk/impact plays on the central shelf of th Gulf of Mexico, the division gains exposure to significant reserve potential, whil maintaining appropriate risk exposure.

Dear Fellow Shareholders,

Much was accomplished in 2002. Proved reserves grew 13%, reaching 578 Bcfe. Drilling more than replaced production for the first time in the Company's history. A reactivated acquisition effort led to $16 million of purchases in core areas. Total reserve replacement reached 222%, and reserves were added at a cost of $0.92 per mcfe. Based on current futures prices, capital expenditures during the year should yield a compound annual return of better than 40%. The only material setback was a 1.7% production decline. Specifically, a 20% decline in the Gulf Coast more than offset an 11% increase in the Southwest and a 4% increase in Appalachia. Realized prices fell 7% to $3.49 per mcfe, as the gas price fell 4% to $3.50 per mcf, and the oil price declined 13% to $22.25 a barrel. Despite an 11% reduction in revenues, net income increased 46% to $26 million as fully diluted earnings per share rose to $0.47. The improvement reflected the absence of property impairments recorded in 2001. Cash flow declined slightly to $118 million or $2.17 per share, primarily due to lower prices. Given the increase in energy prices, financial results in 2003 should reach record levels.

During the year, $95 million was invested in drilling, leasehold acquisition and seismic. A total of 328 gross (178.6 net) wells were drilled. Although more than 70% of drilling capital was spent on projects not previously assigned proved reserves, a 95% success rate was achieved. Material discoveries were made in the Texas Panhandle, in East Texas, on the Gulf Coast and in the Gulf of Mexico. As the majority of the larger wells came on production late in the year, they were unable to overcome shortfalls at Matagorda Island and in the Bossier trend of East Texas. By year-end, volumes had reached their highest level in more than three years.

Although the primary focus in 2002 was on assembling a sizeable inventory of drilling projects, building reserves and increasing production, debt reduction continued. Debt fell $24 million, as $45 million of higher cost subordinated and non-recourse debt was retired, with an increase of only $21 million in bank debt. In December, IPF's separate credit facility was eliminated to reduce interest and administrative cost. Declining debt balances and lower interest rates cut interest expense sharply by 28%. In the coming year, debt should again decline as rising production and higher energy prices are expected to generate higher cash flow.

Cash flow in 2003 will fund rising capital expenditures, along with a mixture of debt reduction and minor acquisitions. Excluding acquisitions, $105 million of capital spending has been budgeted. Projects include $89 million to drill 326 (173.4 net) wells and 37 (26.9 net) recompletions. Continuing to expand the drilling inventory remains a priority, with $12 million allocated for leasehold and seismic purchases and $4 million to fund pipeline and facilities expansion. Geographically, 50% of the budget will be directed to the Southwest and 25% each to the Gulf Coast and Appalachia.

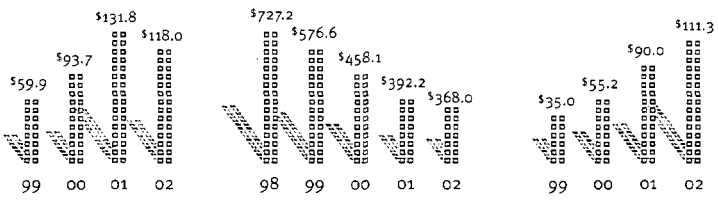
The strategy initiated two years ago shows signs of success. Development drilling and modest complementary acquisitions in core areas, in concert with a controlled exploration effort, have allowed reserves to be added at an attractive cost. Capital investments are yielding extremely attractive returns. The final hurdle is to deliver dependable production growth. Given January volumes and early drilling results, we expect to report modest production growth in the first quarter and to accelerate that growth as the year progresses. The production decline in the Gulf Coast should moderate to roughly 5%. With anticipated increases of 10% – 12% in the Southwest and 5% – 6% in Appalachia, an overall increase of 4% – 7% should be achieved. We will do everything in our power to avoid a recurrence of last year's production decline.

In closing, we wish to express our appreciation for the dedication of our directors and the unstinting effort of our employees. Most importantly, we appreciate the continuing patience and support of our shareholders. We look forward to keeping you apprised of our progress in the months ahead.

Sincerely yours,

Thomas J. Edelman
Chairman

John H. Pinkerton
President

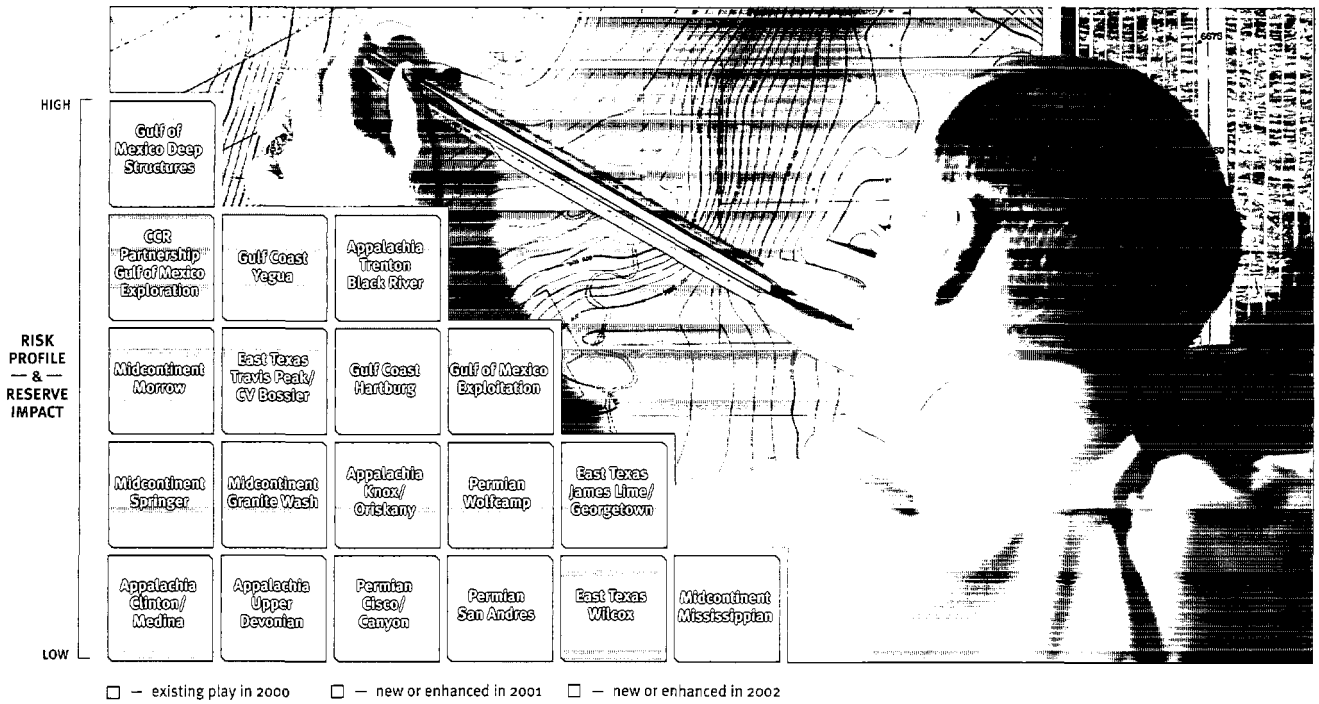


CASH FLOW (MILLIONS)

TOTAL DEBT (MILLIONS)

CAPITAL COSTS (MILLIONS)

OPERATIONAL OVERVIEW

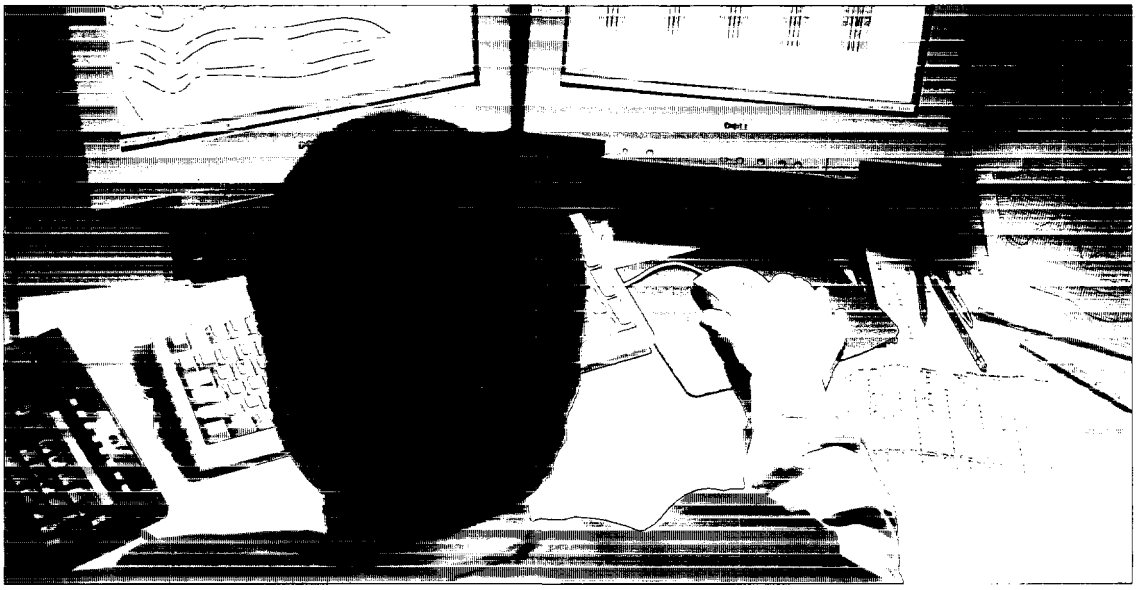


TO ACHIEVE MORE BALANCED GROWTH, WE HAVE ENHANCED OUR TECHNICAL APPROACH BY HIGH-GRADING STAFF AND PROJECT INVENTORY, FUNDING INCREASED INVESTMENT IN LAND AND SEISMIC, AND ELEVATING OUR LEVEL OF EXPLORATION ACTIVITY.

In early 2001, the Company's exploration and production effort was redirected. Previously, the Company grew primarily through acquisitions and associated low-risk development opportunities. The new strategy focuses on achieving organic growth through the drillbit, and seeks to balance a large-scale development program with an increasing number of higher potential exploration projects. Acquisitions within core areas serve to complement drilling. To achieve more balanced growth, we enhanced our technical approach by high-grading staff and project inventory, funding increased investment in land and seismic, and elevating our level of exploration activity while mitigating dry hole risk. Although production growth proved elusive in 2002, with a year-over-year shortfall of 1.7%, we are pleased to have replaced 222% of production at a finding cost of $0.92 per mcfe. Emerging successes such as these indicate that our growth strategy is beginning to reap its intended benefits.

BALANCE — A key element of the new approach is a rebalancing of the Company's drilling portfolio. As indicated in the risk/impact illustration above, three years ago Range's project inventory consisted primarily of low-risk, low-impact opportunities located in West Texas and Appalachia. These development prospects were generally low-cost, but held little potential to grow the reserve base. In the past two years, a number of medium-impact plays have been added in Midcontinent, East Texas, onshore Gulf Coast and Appalachia. These prospects generally are more costly to exploit and carry higher risk. However, they target larger reserve accumulations having the potential for material reserve additions. Finally, the top two tiers of the pyramid have recently been added. These represent higher risk, higher impact plays in the deeper structures of the Gulf of Mexico as well as onshore. Generally, these prospects have relatively high costs and high risk exposure. When successful, they can generate significant reserve additions. One of the Company's stated goals is to develop a series of high-potential projects each year which involves a significant degree of risk but substantial prospective return.

RISK MANAGEMENT — As certain of these exploration projects may involve high dry hole costs, the Company often brings in industry partners on a promoted basis in order to limit financial exposure. Although the Company plans to participate in up to 26 exploratory wells in 2003, it will limit expenditures to no more than 10% to 15% of the total capital. We will also continue investing in seismic data at a higher level than in the past. By equipping our geologists and geophysicists with state-of-the-art seismic, we are multiplying the number of higher potential prospects we drill without substantially adding



WE REPLACED 222% OF PRODUCTION AT A FINDING COST OF $0.92 PER MCFE IN 2002. IN 2003, WE ARE INCREASING OUR CAPITAL BUDGET TO $105 MILLION AND ARE INTENT UPON DEMONSTRATING DEPENDABLE PRODUCTION GROWTH.

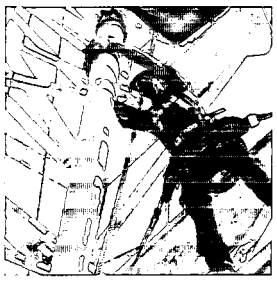
to dry hole risk. An example of how investment in seismic is reaping benefits can be found in the Gulf Coast division. Over the past two years, the division has spent nearly $1 million on seismic, including the reprocessing of 3-D seismic as pre-stack, time-migrated data. This technique brings to light a new set of seismic attributes and enables our technical staff to identify previously overlooked opportunities. This technique was used to identify both of the deeper continental shelf discoveries made in 2002 at West Cameron 45 and Ship Shoal 28. Similar opportunities have been slated for drilling in 2003.

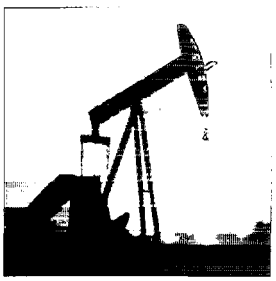
GEOGRAPHIC DIVERSIFICATION — Currently, Range conducts operations in three core areas. These include Southwest, Gulf Coast and Appalachia. Concentrating our drilling efforts in multiple core areas allows us to develop the regional expertise needed to interpret specific geological trends. Operating in multiple areas allows us to combine the production characteristics of each area to balance our portfolio. For example, highly predictable, long-lived Appalachian wells help mitigate the risk and rapid decline inherent in high-rate, short-lived Gulf wells. Our overall goal is to maintain a long-lived reserve base and achieve consistently favorable financial results.

ACQUISITIONS — During the retrenchment of 1999-2001, the Company withdrew from acquisitions. In 2002, the program was reinstated, and $15.6 million of purchases was completed. The two largest purchases included producing wells and undeveloped acreage in the Watonga-Chickasha trend of Oklahoma and in the Clinton-Medina trend of Appalachia. A complementary acquisition effort will continue in 2003. Although the Company targets incremental acquisitions in existing core areas, one of our current growth initiatives includes identifying acquisition candidates where existing scientific knowledge is transferable.

FLEXIBILITY — Each year, the Board approves a capital budget from which we develop our drilling program. Given the volatility of commodity prices and the risks involved in drilling, we remain flexible in our approach. Should commodity prices drop, we may defer capital projects in order to seize an exceptional acquisition opportunity. If certain areas generate higher than anticipated returns, we may accelerate drilling in the trend and decrease capital elsewhere. Such was the case in the Morrow play of the Texas Panhandle. Encouraging initial results have caused us to increase capital spending for leasehold and drilling. In 2001, we redefined the Company's strategy to grow through a balanced effort of exploration, development and acquisitions. In 2002, successful exploratory and step-out drilling, along with complementary acquisitions, combined to establish new areas for future growth. In 2003, we anticipate building upon this progress. We are focused on picking up the pace at which we identify new drilling prospects, acquire leasehold and commence drilling operations. Most importantly, we are focused on building upon the production momentum that was achieved late in the fourth quarter. Our 2003 capital budget of $105 million represents a 10% increase over the prior year and will largely be directed toward unproved projects. While the attempt to transform Range into a more balanced and more technically driven Company is still in an early stage, as indicated in the divisional summaries that follow, evidence of success is increasing.

OPERATIONAL HIGHLIGHTS





SOUTHWEST

The Southwest division's properties are located in the Permian Basin of West Texas, the East Texas Basin, and the Anadarko Basin of western Oklahoma and the Texas Panhandle. In 2002, the division spent $56.8 million to drill 72 (64.9 net) wells, achieving a 92% success rate. Reserves increased 16%, with 34.0 Bcfe added through drilling and 7.6 Bcfe added through acquisitions. The division replaced 230% of its production, achieving 122% reserve replacement if pricing revisions are excluded. Production from the Southwest, which averaged 71.5 Mmcfe per day, represented an 11% increase over the prior year and 48% of the Company total. Year-end reserves totaled 239.7 Bcfe or 41% of the Company total with a PV10 value of $412.7 million. Reserves are 61% gas and have a reserve life index of 9.2 years. A farm-in in the Texas Panhandle that yielded a significant discovery, the initiation of a pilot waterflood program in West Texas and our first operated horizontal well testing the James Lime play in East Texas were highlights of the division's activity in 2002.

> With our waterflood redevelopment project at Fuhrman-Mascho and step-out drilling in the Sterling field of West Texas, our technical team increased production in mature areas.

WEST TEXAS

Fuhrman-Mascho. Located in Andrews County, Texas, this field exemplifies how Range is employing improved technical abilities to increase production in areas previously believed to be fully developed. In the 1980s, another company initiated a redevelopment effort at Fuhrman-Mascho designed to flood the underlying structures with water and essentially displace the remaining oil from the rock fractures. Unfortunately, much of the water channeled into a porous geological zone, known as a "thief" zone, and the waterflood attempt proved unsuccessful. After a full technical study, the Southwest division initiated an improved waterflood project in 2002. The current program has an increased injector/producer ratio, reduced well spacing, an altered drilling pattern and a new approach to sealing off the "thief" zone. Results are not anticipated until mid-2003. Due to the increased number of wells, production in the field almost doubled in 2002. In total, 20 (19.4 net) wells were drilled in 2002. With preliminary results exceeding pre-drill expectations, an additional 20 (19.4 net) wells are planned in 2003.

Sterling. In 2002, 15 (13.8 net) infill and step-out wells were drilled in Sterling County, Texas. Successful step-out drilling extended the field to the east. Net production, which currently approximates 14.1 Mmcfe per day, is up 14% over the prior year-end. In 2003, an additional 10 (9.8 net) wells are planned in the field.

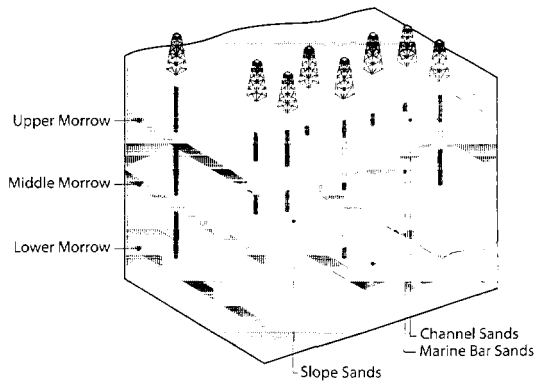
Val Verde. With interests in 200+ wells, Range targets the gas-prone sands of the Val Verde Basin. Wells are drilled to the Canyon Sands and Strawn Lime formations at depths of 3,500 to 8,500 feet. In 2002, 5 (2.8 net) infill and step-out wells were drilled. At year-end, net production from this field approximated 8.3 Mmcfe per day. In 2003, 8.0 (5.7 net) wells and 13.0 recompletions are planned at Val Verde.

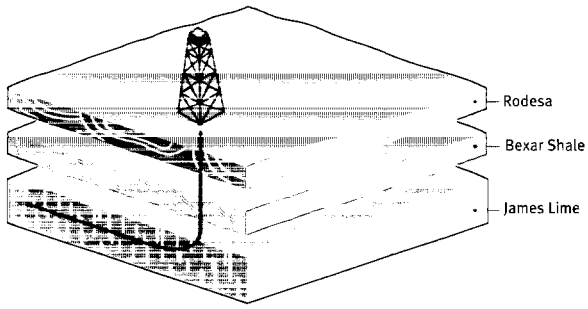
Powell Ranch. Range purchased the Powell Ranch in Glasscock County, Texas in 1998. After shooting new 3-D seismic, over 20 wells have been drilled in the field to date. In 2002, 3.0 (2.7 net) wells were successfully completed, bringing total field production to 11.1 net Mmcfe per day. One new well is planned here in 2003.

EAST TEXAS

James Lime. In 2002, Range drilled its first operated well to test the James Lime formation. The ALC #1-H (100% WI) was a horizontal discovery well drilled on the O'Dell Creek

SOUTHWEST MORROW SANDS





SOUTHWEST JAMES LIME

prospect in Angelina County, Texas. Although the well came on stream at 4.0 Mmcfe per day, it declined to 0.5 Mmcfe per day in a short period of time. Range's technical staff attributed the swift decline partially to the completion design. Revised completion techniques are expected to reduce per well costs by 35% and help moderate the decline. With this, three wells are planned for the first half of 2003 to further test the formation. The Company has identified a number of promising leads in the play, but plans are predicated on future drilling results.

Laura La Velle. In 2002, the first phase of a three-phase, high-volume lift program was completed, increasing production 10.5%. In total, 4 (3.3 net) wells were drilled to the East Texas Carrizo/Massive Wilcox formation at depths of 1,500 to 1,600 feet. Net production in the field currently approximates 2.9 Mmcfe per day. The second phase of the high-volume lift program will be initiated in 2003.

Travis Peak. In late 2001, Range's attempts in the Bossier play in East Texas resulted in a discovery in the Travis Peak formation, a secondary objective. At year-end, this discovery and two offset wells were producing at 1.4 Mmcfe per day. No wells are currently planned during 2003.

IN 2002, THE SOUTHWEST DIVISION DRILLED ITS INITIAL OPERATED HORIZONTAL WELL IN EAST TEXAS AND NEARLY TRIPLED LEASEHOLD IN ITS TEXAS PANHANDLE MULTI-PAY TREND. WITH CONTINUED SUCCESS, BOTH AREAS OFFER SIGNIFICANT ROOM FOR FUTURE EXPANSION.

TEXAS PANHANDLE

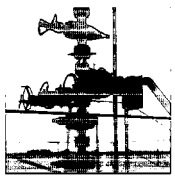
Morrow Play. The Morrow play in the Texas Panhandle continues to provide significant growth opportunities. Characterized by multiple sands and depositional environments within a single formation, the Upper, Middle and Lower Morrow Sands produce at depths of 7,000 to 12,000 feet with expected reserves ranging from 1 to 5 Bcfe per well. Active in the area since 1999, Range nearly tripled its acreage position in 2002, currently holding more than 62,000 (49,500 net) acres in the play and 307 miles of 3-D seismic and regional subsurface mapping. In 2002, Range drilled a total of 11 (10.1 net) Morrow wells with a 73% success rate. The 8 (7.7 net) successful wells drilled in 2002 are currently producing at a rate of 8.8 (6.5 net) Mmcfe per day. Each new well has enhanced our ability to interpret key seismic reflectors. Significant wells drilled in the area in 2002 were the Pioneer #2, the Intrepid #1-107 and the Courson Ranch #1-140. The Pioneer #2 (100% WI) in the Ben Hill area of northeast Roberts County tested over 8.3 (6.6 net) Mmcfe per day from the targeted Lower Morrow Sand, and after 11 months of production is currently delivering in excess of 3.1 (2.5 net) Mmcfe per day. Two significant uphole Morrow zones identified during drilling are available for future recompletion. The Courson Ranch #1-140 (73% WI) was an exploratory discovery in northwest Roberts County that encountered 31 net feet of pay in the Upper Morrow sand. The well initially tested at rates exceeding 1,000 (546 net) barrels of oil per day and is currently producing at the full allowable proration rate of 340 (186 net) barrels and 0.3 (0.2 net) Mmcf per day. The first infill location commenced in January 2003. An additional 11 wells, which will test the Upper Morrow and various other objectives, are planned in 2003 within the 32 square mile 3-D seismic grid. Range controls 34,269 (25,702 net) acres in this prospect area. In Hansford County, northwest of Courson Ranch, the Intrepid #1-107 (97% WI) encountered pay in the Middle Morrow Sand. The well initially flowed at 2.2 (1.7 net) Mmcfe per day and is currently producing at that same rate. Additional offsets are planned for 2003 and several similar prospects have been identified for future drilling. A total of 20 (15.9 net) wells are planned to test Morrow objectives in 2003.

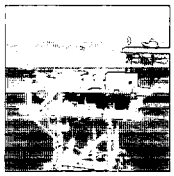
ANADARKO BASIN

Western Oklahoma. In 2002, Range drilled a total of 8 (5.4 net) wells in the Sooner, Watonga-Chickasha, Granite Wash and Northwest Shelf trends of the Anadarko Basin. The notable success in the Watonga-Chickasha trend area was the Endeavour #1-28 (100% WI), which completed in the Morrow/Springer sands and tested in excess of 1.2 (0.9 net) Mmcfe per day. The Watonga-Chickasha area was also the location of property acquisitions for the division. In 2002, 14 wells (8.0 net) were acquired in the area, adding approximately 2.3 net Mmcfe per day to production. Range participated in the drilling of one successful well on the leasehold in late 2002. In 2003, Range plans to drill 3 (1.7 net) wells on these newly acquired properties, along with 1 (0.8 net) well on previously owned properties.

2003 PLANS

The Southwest division plans to spend approximately $50 million in 2003 to drill 70-80 gross wells. Test drilling will continue in the James Lime trend of East Texas and the Courson Ranch area in the Texas Panhandle. Developmental and step-out drilling is planned for West Texas, with results from the waterflood expected by mid-year. Field studies will continue in East Texas, exploring for deeper prospects on existing properties and evaluating potential new prospect areas.





GULF COAST

Gulf Coast operates properties onshore in Texas, Louisiana and Mississippi and holds an interest in 40 offshore platforms in the shallow waters of the Gulf of Mexico. In 2002, the division spent $19.8 million of capital to drill 8 (2.3 net) wells, recomplete 7 (2.2 net) others and upgrade facilities. Gulf Coast drilling added 9.5 Bcfe, with approximately 6.4 Bcfe of reserves booked on the West Cameron and Ship Shoal discoveries. Production, which averaged 44.7 Mmcfe per day, represented 30% of the Company total and a 20% decline compared to the prior year. The production loss was a result of the Gulf's natural decline rate as well as mechanical and storm-related shut-ins. The Gulf Coast replaced only 35% of its production during 2002. Year-end reserves declined 10% to 86 Bcfe, representing 15% of the Company total and a PV10 value of $198 million. The Gulf Coast's reserves are 88% natural gas and have a reserve life index of 5.3 years. In spite of the production decline, the division had a very successful drilling year, achieving a 100% success rate. Highlights included participation in two significant offshore discoveries. In addition, an onshore discovery in Louisiana is leading to additional drilling.

THE GULF COAST DIVISION HAS IDENTIFIED 46 LEADS TO DATE USING AN EXTENSIVE LIBRARY OF 3-D SEISMIC DATA. REPROCESSED 3-D DATA IS ENABLING OUR TECHNICAL TEAM TO IDENTIFY PREVIOUSLY OVERLOOKED OPPORTUNITIES, SUCH AS THE WEST CAMERON AND SHIP SHOAL DISCOVERIES DRILLED IN 2002.

GULF OF MEXICO JOINT VENTURE

The Gulf of Mexico joint venture, formed between Range, Callon Petroleum and Cheyenne Petroleum to explore the central shelf, successfully drilled its first joint well in 2002. This exploratory well, the Ship Shoal 28 #40, encountered 140 feet of net gas pay. The venture's explorationists generated the prospect by utilizing 3-D seismic reprocessed as pre-stack, time-migrated data. To date, the venture has spent $2.1 million on additional seismic, providing access to almost 6,100 square miles of 3-D data covering 780 contiguous offshore blocks, of which approximately 1,500 square miles is licensed as reprocessed pre-stack, time-migrated data. Throughout the year, the joint technical team continued working the data, identifying 22 new leads, bringing the total number of prospects to 46. The venture continues to pursue leases and farm-ins to capture these opportunities. Plans in 2003 include participation in at least two offshore wells in which Range will have a quarter working interest.

OFFSHORE DRILLING

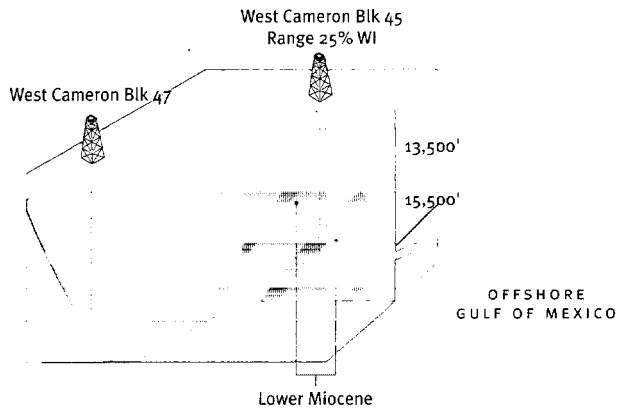
Range participated in the drilling of three wells in the Gulf of Mexico in 2002. All three wells encountered pay at their objective horizons. Most notable was the 16,444 foot West Cameron 45 #20 well, which came online in mid-December and is currently producing in excess of 30 (6.0 net) Mmcf per day. In August 2002, Range participated in a well drilled on Vermilion Block 332. This shallow test, in which Range has a 16.5% working interest, encountered gas pay in two horizons. First sales occurred February 15 at a rate of 5 (0.6 net) Mmcf per day. Finally, in October of 2002 the Ship Shoal 28 #40 well was spud. This successful exploratory well was drilled to a measured depth of 15,237 feet, encountering 140 net feet of gas pay. Range has a 26.8% working interest. The well has been tested at rates as high as 12 (2.4 net) Mmcf per day, with first production anticipated in the second quarter of 2003.

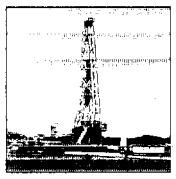
ONSHORE DRILLING

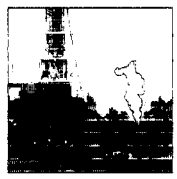
The division participated in the drilling of four onshore wells in 2002. Most significant was the Arceneaux #1 well located in Vermilion Parish, Louisiana. This Range-operated discovery began producing in late August. The well is currently producing gas at rates in excess of 6.3 (2.0 net) Mmcf per day. A second test well was spud nearby in first quarter 2003. Results of this exploratory test will help determine Range's ability to expand the play. Of the other three wells, two were successfully completed and are producing at a combined rate of 2.5 (0.5 net) Mmcfe per day. The third well was initially a producer, but recently sanded up. Range has not elected to participate in attempts to restore production to this well.

2003 PLANS

The division plans to spend approximately $25 million in 2003 to drill 9 to 15 wells and will be evaluating the areas surrounding West Delta 30 and Arceneaux #1 as potential sites for core area expansion. Outside of the joint venture, one additional high risk/reward prospect in the shallow water Gulf is planned.







APPALACHIA

Through its 50% interest in Great Lakes Energy Partners L.L.C., the Company operates in the Appalachian and Michigan Basins of the northeastern United States.

Drilling activity targets low-risk shallow development plays, as well as deeper formations with higher risk/reward potential. During 2002, Range spent $20.2 million net to drill 242 (105.4 net) wells, achieving a 95% success rate.

During the year, the division also added 167,012 (70,315 net) acres of leasehold and shot or acquired 825 miles of 2-D and 3-D seismic. This represented the largest development program in the division's history. A notable highlight was the acquisition of 9.3 Bcfe of reserves in New York and Pennsylvania.

In 2002, Appalachia added a total of 30.0 Bcfe of reserves through drilling and acquisitions. The division replaced 198% of its production with drilling and achieved total reserve replacement of 444%, or 287% if price revisions are excluded. Appalachia production, which averaged 33.9 Mmcfe per day, represented a 4% increase over 2001 production and 23% of the Company total. Reserves totaled 252 Bcfe or 44% of the Company's total reserves with a PV10 value of $354 million. Reserves are 86% natural gas and have a reserve life index of 20.4 years.

APPALACHIAN DRILLING PRIMARILY TARGETS SHALLOW, LOW-RISK DEVELOPMENT WELLS THAT OFTEN PRODUCE FOR 25 YEARS OR LONGER. IN 2003, OUR 1.2 MILLION GROSS ACRE LEASEHOLD POSITION PROVIDES THE OPPORTUNITY TO CONTINUE EXPANDING IN EXISTING FIELDS, TO TEST MULTIPLE NEW SHALLOW PROJECT AREAS AND TO DRILL SEVERAL HIGHER IMPACT, DEEP WELLS.

SHALLOW DRILLING

The majority of the division's drilling expenditures are directed toward two large shallow-development plays which include the Clinton-Medina and Upper Devonian sandstone trends. In 2002, Range drilled 160 (70.15 net) wells in the Clinton-Medina and 52 (24.6 net) wells in the Upper Devonian shallow plays with an overall success rate of 99%. Approximately 84% of the division's capital budget will target shallow drilling in 2003, funding the drilling of 160 (70.2 net) Clinton-Medina wells and 55 (27.5 net) Upper Devonian wells.

A key component of the division's growth strategy is to seek expansion of its shallow development plays beyond the current core fields. An aggressive leasing program which began in 2001 has created a number of new opportunities that will be initially tested in 2003, including pilot programs in six new shallow project areas.

MEDIUM AND DEEP DRILLING

Approximately 14% of the division's 2002 capital budget targeted the medium and deep plays. These include the Knox Unconformity, the Huntersville Chert/Oriskany sandstone and the Trenton Black River plays. Of the 25 (8.1 net) medium/deep wells drilled, 16 (5.35 net) proved successful, resulting in a 64% success rate. The 2003 budget for these deeper trends is $3.5 million and includes 22 (8.2 net) wells.

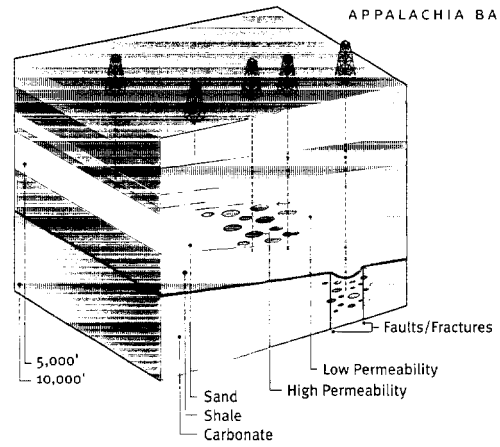
In 2002, Appalachia drilled 22 (7.1 net) wells to the Knox Unconformity and Huntersville/Oriskany plays, of which 14 (4.7 net) proved productive. Leasehold and seismic position also expanded. In 2003, the division plans to test various other prospective areas in these medium depth plays, drilling up to 18 (7.4 net) wells.

The Trenton Black River play, which spans portions of New York, Pennsylvania and West Virginia, has produced several major gas discoveries in recent years by other operators, with reserves ranging from 0.5 Bcfe to as much as 5 Bcfe per well. Over the past several years, the Appalachia division has focused on accumulating 115,972 (36,290 net) acres in four major Trenton Black River plays, as well as acquiring and evaluating 206 miles of seismic data and forming several industry drilling joint venture groups. In 2003, the Company plans 4 (0.8 net) wells to test the trend.

2003 PLANS

With over 1,600 in-field development locations in inventory, the Clinton-Medina and Upper Devonian plays will remain the division's primary focus. Key development plans for 2003 include the continued expansion of the Company's shallow plays and testing of several new shallow project areas. In 2003, deeper drilling efforts are expected to continue on a selective basis, including testing of several high-potential Trenton Black River projects.

APPALACHIA BASIN



MARKET FOR COMMON STOCK AND RELATED MATTERS

The Company's common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "RRC." During 2002, trading volume averaged 142,554 shares per day. On March 1, 2003, the closing price of the common stock was $5.93. The following table sets forth the quarterly high and low sales prices and volumes as reported on the NYSE composite tape for the past two years.

	High	Low	Average Daily Volume
2002			
First quarter	$5.45	$4.03	155,882
Second quarter	5.91	4.95	160,475
Third quarter	5.68	4.05	145,836
Fourth quarter	5.96	4.05	108,856
2001			
First quarter	7.13	5.15	374,390
Second quarter	6.68	4.90	392,240
Third quarter	6.20	4.25	353,008
Fourth quarter	4.76	3.93	240,491

Between January 1, 2003 and March 1, 2003, the common stock traded at prices between $5.20 and $6.20 per share. The Company's 5.75% Trust preferred, 6% Convertible debentures and 8.75% Senior subordinated notes are not listed on an exchange, but trade over the counter.

At various times in 2002, the Company issued common stock in exchange for fixed income securities. Shares of common stock issued in such exchanges were exempt from registration under Section 3(a) (9) of the Securities Act of 1933. The following table summarizes those exchanges in 2002, 2001 and 2000:

	Face Amount ($000)			Common Stock Issued (000's)		
	2002	2001	2000	2002	2001	2000
Security Exchanged						
8.75% Subordinated Notes	$ 875	$ 3,385	$ -	175	754	-
6% Debentures	7,140	5,710	13,810	1,150	745	2,448
5.75% Trust preferred	2,400	2,850	25,029	283	291	3,231
$2.03 Preferred stock	-	5,425	23,246	-	767	4,584
	$10,415	$17,370	$62,085	1,608	2,557	10,263
Market value at date of exchange				$ 8,242	$14,207	$36,910

HOLDERS OF RECORD

At March 1, 2003, there were approximately 2,308 holders of record of the common stock.

DIVIDENDS

Quarterly common stock dividends were initiated in 1995. In connection with the Company's need to reduce leverage, the dividend was reduced in the first quarter and eliminated in the fourth quarter of 1999. The Parent bank facility and the 8.75% Senior subordinated notes contain restrictions on the payment of dividends. Since January 1, 2003, the Parent bank facility has permitted dividends. Under the 8.75% senior subordinated notes, the Company may pay restrictive payments, including dividends, equal to the greater of: i) $20.0 million or ii) a formula which includes earnings and losses since the issuance of the notes. Given its losses since 1997, the Company cannot make payments under the formula and must rely on the $20.0 million basket. At December 31, 2002, only $803,000 remained available under the basket. The Company may seek to amend this covenant.

SELECTED FINANCIAL DATA

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

(in thousands, except per share data)	As of or for the Year-Ended December 31,				
	2002	2001	2000	1999	1998
Operations					
Revenues	$195,338	$219,425	$184,828	$193,047	$148,929
Net income (loss)	25,766	17,663	36,578	(23,542)	(181,273)
Earnings (loss) per share					
Before extraordinary gain					
-Basic	0.45	0.28	0.55	(0.78)	(7.11)
-Diluted	0.44	0.28	0.54	(0.78)	(7.11)
After extraordinary gain					
-Basic	0.49	0.36	0.97	(0.71)	(7.11)
-Diluted	0.47	0.36	0.96	(0.71)	(7.11)
Dividends per share	-	-	-	0.03	0.12
Balance Sheet					
Working capital (deficit) [a]	$ (29,852)	$ 29,856	$ 9,665	$ 20,011	$ (8,198)
Oil and gas properties, net	564,406	533,357	553,173	570,643	653,260
Total assets	658,484	682,462	671,826	732,228	913,970
Senior debt	115,800	95,000	89,900	140,000	367,062
Non-recourse debt	76,500	98,801	113,009	142,520	60,100
Subordinated debt	90,901	108,690	162,550	176,360	180,000
Trust preferred	84,840	89,740	92,640	117,669	120,000
Stockholders' equity [b]	206,109	235,621	159,944	103,238	125,669

(a) Refer to Company's detailed balance sheet for hedging amounts included herein.

(b) Stockholders' equity includes other comprehensive income (loss) of $(21.2 million), $45.5 million, $(639,000), $189,000 and $292,000 in 2002, 2001, 2000, 1999 and 1998, respectively.

SELECTED FINANCIAL DATA

The following table sets forth summary unaudited financial information on a quarterly basis for the two years ended December 31, 2002.

(in thousands, except per share data)

	March 31	June 30	September 30	December 31	Total
2002					
Revenues	$ 44,219	$ 49,307	$ 50,337	$ 51,475	$195,338
Net income [a]	4,341	7,310	9,222	4,893	25,766
Earnings per share - basic	0.08	0.14	0.17	0.09	0.49
- diluted	0.08	0.13	0.17	0.09	0.47
Total assets	644,502	640,222	637,901	658,485	658,484
Senior debt	99,600	98,300	101,600	115,800	115,800
Non-recourse debt	95,100	92,000	87,100	76,500	76,500
Subordinated debt	106,300	95,691	91,206	90,901	90,901
Trust preferred	87,340	87,340	84,840	84,840	84,840
Stockholders' equity	216,221	220,639	217,586	206,111	206,109

	March 31	June 30	September 30	December 31	Total
2001					
Revenues	$ 63,105	$ 58,445	$ 52,143	$ 45,732	$219,425
Net income [b]	20,053	16,968	8,198	(27,556)	17,663
Earnings per share - basic	0.42	0.34	0.16	(0.54)	0.36
- diluted	0.41	0.33	0.16	(0.54)	0.36
Total assets	658,825	695,418	584,373	682,462	682,462
Senior debt	76,800	88,800	95,000	95,000	95,000
Non-recourse debt	98,006	99,902	102,501	98,801	98,801
Subordinated debt	160,940	133,340	121,840	108,690	108,690
Trust preferred	92,640	90,290	90,290	89,740	89,740
Stockholders' equity	151,136	222,064	247,635	235,621	235,621

(a) Includes extraordinary gains (net of taxes) of $770,000, $545,000, $687,000 and $12,000 in the first, second, third and fourth quarters, respectively.

(b) Includes extraordinary gains on retirement of securities of $432,000 in the first quarter. These gains were $895,000 and $319,000 in the second and third quarters (net of taxes), respectively. In the fourth quarter of 2001, the gain on retirement of securities was $2.3 million (net of taxes). The fourth quarter includes an impairment charge of $31.1 million.

The total of quarterly earnings per share does not necessarily equal the earnings per share for the year, either because the calculations are based on the weighted average shares outstanding or rounding. During the fourth quarter of 2001, the Company recorded $31.1 million of impairments. (See Management's Discussion and Analysis – Results of Operations.)

RESTATEMENT

For many years, Arthur Andersen LLP served as the Company's auditor. In July 2002, the Company selected KPMG LLP as its new independent auditor. Simultaneously, the Company asked KPMG to reaudit its consolidated financial statements for the three years ended December 31, 2001, even though a reaudit was not required. The reaudit was intended to provide additional assurance to shareholders, ensure the Company's ongoing access to the capital markets and to avoid any possible impediment to future transactions. As a result of the reaudit, the financial statements were restated. For the three years ended December 31, 2001, the cumulative impact of the restatements reduced net income by $8.4 million, of which $7.8 million related to the reduction of the gain associated with the formation of Great Lakes in 1999. The restatement increased the 1999 net loss by $15.7 million, reduced 2000 net income by $1.4 million, increased 2001 net income by $8.7 million and reduced first half of 2002 net income by $2.3 million.

Capitalized terms are defined in the footnotes to the consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Company's discussion and analysis of its financial condition and results of operation are based upon consolidated financial statements which have been prepared in accordance with accounting principles generally adopted in the United States. The preparation of these financial statements requires the Company to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Application of certain of the Company's accounting policies, including those related to oil and gas revenues, bad debts, the fair value of derivatives, oil and gas properties, marketable securities, income taxes and contingencies and litigation require significant estimates. The Company bases its estimates on historical experience and various assumptions that are believed reasonable under the circumstances. Actual results may differ from these estimates. The Company believes the following critical accounting policies affect its more significant judgments and estimates used in the preparation of its financial statements.

Proved reserves. Proved reserves are defined by the U.S. Securities and Exchange Commission ("SEC") as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods. Although the Company's engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserves estimates are updated at least annually and consider recent production levels and other technical information about each well. Estimated reserves are often subject to future revision, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors. Changes in oil and gas prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in the depletion rates utilized by the Company. The Company cannot predict what reserve revisions may be required in future periods.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the costs capitalized. Estimated reserves are used as the basis for calculating the expected future cash flows from a property, which are used to determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to its oil and gas producing activities and reserve quantities disclosure in Footnote 19 to the consolidated financial statements. Changes in the estimated reserves are considered changes in estimates for accounting purposes and are reflected on a prospective basis.

Successful efforts accounting. The Company utilizes the successful efforts method to account for exploration and development expenditures. Unsuccessful exploration wells are expensed and can have a significant effect on operating results. Successful exploration drilling costs and all development costs are capitalized and systematically charged to expense using the units of production method based on proved developed oil and gas reserves as estimated by the Company's engineers. The Company also uses proved developed reserves as the divisor to accrue the expense of estimated future dismantlement and abandonment costs. At year-end, the Company had a liability totaling $32.1 million for plugging and abandonment costs on its balance sheet. This liability is shown netted against oil and gas properties on the balance sheet. Currently, the Company estimates it will spend $13.2 million over the next three years on plugging and abandonment costs. The Company will adopt SFAS 143 on January 1, 2003 which changes the accounting treatment for these types of costs. See Note 2 to the Consolidated financial statements "Recent Accounting Pronouncements" for further discussion.

Impairment of properties. The Company continually monitors its long-lived assets recorded in Property, plant and equipment in the Consolidated Balance sheet to ensure they are fairly presented. The Company must evaluate its properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future oil and natural gas sales prices, an estimate of the ultimate amount of recoverable oil and gas reserves that will be produced from a field, the timing of future production, future production costs and future inflation. The need to test a property for impairment can be based on several factors, including a significant reduction in sales prices for oil and/or gas, unfavorable adjustment to reserves, or other changes to contracts, environmental regulations or tax laws. All of these factors must be considered when testing a property's carrying value for impairment. The Company cannot predict whether impairment charges may be required in the future.

Income taxes. The Company is subject to income and other similar taxes in all areas in which it operates. When recording income tax expense, certain estimates are required because: (a) income tax returns are generally filed many months after the close of a calendar year; (b) tax returns are subject to audit which can take years to complete; and (c) future events often impact the timing of when income tax expenses and benefits are recognized. The Company has deferred tax assets relating to tax operating loss carryforwards and other deductible differences. The Company routinely evaluates all deferred tax assets to determine the likelihood of realization. A valuation allowance is recognized on deferred tax assets when management believes that certain of these assets are not likely to be realized.

The Company's deferred tax assets exceeded its deferred tax liabilities at year-end 2001 before considering the effects of Other comprehensive income (loss) ("OCI"). In determining deferred tax liabilities, accounting rules require OCI to be considered, even though such income (loss) has not yet been earned. The inclusion of OCI caused deferred tax liabilities to exceed deferred tax assets by $4.5 million at year-end 2001, and this amount was recorded as a deferred tax liability on the balance sheet. At year-end 2002, deferred tax assets exceeded deferred tax liabilities by $15.8 million with $11.4 million of deferred tax assets related to deferred hedging losses included in OCI. Based on the Company's projected profitability, no valuation allowance was deemed necessary.

The Company occasionally is challenged by taxing authorities over the amount and/or timing of recognition of revenues and deductions on its various income tax returns. Although the Company believes that it has adequate accruals for unresolved tax matters, gains or losses could occur in the future due to changes in estimates or resolution of outstanding matters.

Legal, environmental and other contingent matters. A provision for legal, environmental and other contingent matters is charged to expense when the loss is probable, and the cost can be reasonably estimated. Judgment is often required to determine when expenses should be recorded for legal, environmental and contingent matters. In addition, the Company often must estimate the amount of such losses. In many cases, management's judgment is based on an interpretation of laws and regulations, which can be interpreted differently by regulators and/or the courts. Management closely monitors known and potential legal, environmental and other contingent matters and makes its best estimate of when the Company should record losses for these based on available information.

Other significant accounting policies requiring estimates include the following: The Company recognizes revenues from the sale of products and services in the period delivered. Revenues at IPF are recognized as earned. We provide an allowance for doubtful accounts for specific receivables we judge unlikely to be collected. At IPF, all receivables are evaluated quarterly and provisions for uncollectible amounts are established. Such provisions for uncollectible amounts are recorded when management believes that a related receivable is not recoverable based on current estimates of expected discounted cash flows. The Company records a write down of marketable securities when the decline in market value is considered to be other than temporary. Changes in the value of the ineffective portion of all open hedges is recognized in earnings quarterly. The fair value of open hedging contracts is an estimated amount that could be realized upon termination. The Company stock held in the deferred compensation plan is treated as treasury stock and the carrying value of the deferred compensation is adjusted to fair value each reporting period by a charge or credit to operations in general and administrative expense.

FACTORS AFFECTING FINANCIAL CONDITION AND LIQUIDITY

Liquidity and Capital Resources

During 2002, the Company spent $111.3 million on development, exploration and acquisitions. Fixed income obligations including Trust preferred were reduced by $24.2 million. At December 31, 2002, the Company had $1.3 million in cash, total assets of $658.5 million and a debt (including Trust preferred) to capitalization (including debt, deferred taxes and stockholders' equity) ratio of 64%. Available borrowing capacity on the Company's bank lines at December 31, 2002 was $31.1 million on the Parent credit facility and $52.0 million

at Great Lakes (of which $26.0 million was net to Range). Long-term debt (including Trust preferred) at December 31, 2002 totaled $368.0 million and included $115.8 million of borrowings under the Parent credit facility, $76.5 million under the non-recourse Great Lakes facility, $69.3 million of 8.75% Senior subordinated notes, $21.6 million of 6% Convertible subordinated debentures and $84.8 million of Trust preferred. At December 31, 2002, the Company had a working capital deficit of $29.8 million which included a net hedging liability of $26.0 million due to the mark-to-market of all open hedges. Because payments on this hedging liability are made monthly, and the Company will also collect production proceeds to which this hedging relates, the amount should be self-funding.

During 2002, 1.6 million shares of common stock were exchanged for $2.4 million of Trust preferred, $875,000 of 8.75% Senior subordinated notes and $7.1 million of 6% Debentures. In addition, $815,000 of 6% Debentures, $9.0 million of 8.75% Senior subordinated notes and $2.5 million of 5.75% Trust preferred were repurchased for cash. A $3.1 million extraordinary gain ($2.0 million after tax) was recorded, as the securities were retired at a discount. Since 1998, 15.2 million shares of common stock have been exchanged for $95.8 million face value of debt and convertible preferred stock.

The Company believes its capital resources are adequate to meet its requirements for at least the next 12 months. However, future cash flows are subject to a number of variables including the level of production and prices as well as various economic conditions that have historically affected the oil and gas business. A material drop in oil and gas prices or a reduction in production and reserves would reduce the Company's ability to fund capital expenditures, reduce debt and meet financial obligations. In addition, the Company's high depletion, depreciation and amortization rate may make it difficult to remain profitable if oil and gas prices decline substantially. The Company operates in an environment with numerous financial and operating risks, including, but not limited to, the ability to acquire reserves on an attractive basis, the inherent risks of the search for, development and production of oil and gas, the ability to sell production at prices which provide an attractive return and the highly competitive nature of the industry. The Company's ability to expand its reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, borrowings or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain planned capital expenditures.

The following summarizes the Company's contractual financial obligations at December 31, 2002 and their future maturities (in thousands):

	Less than 1 Year	1 – 3 Years	After 3 Years	Total
Long-term debt	$ -	$192,300[a]	$175,741	$368,041
Non-cancelable operating lease obligations	1,808	2,663	299	4,770
Total contractual cash obligations	$1,808	$194,963	$176,040	$372,811

(a) Due at termination dates in each of the Company's credit facilities, which the Company expects to renew, but there is no assurance that can be accomplished.

Total long-term debt (including Trust preferred) at December 31, 2002, was $368.0 million. Long-term debt of $192.3 million was subject to floating interest rates (of which certain amounts have interest swap agreements) and $175.7 million of debt had a fixed interest rate. The table below describes the Company's required annual fixed interest payments on these debt instruments (in thousands):

Security	Amount	Annual Interest	Interest Payable	Maturity
8.75% Sr. sub. notes	$ 69,281	$ 6,062	January, July	2007
6% Debentures	21,620	1,297	February, August	2007
5.75% Trust preferred	84,840	4,878	Feb., May, Aug., Nov.	2027
	$175,741	$12,237		

Cash Flow

The Company's principal sources of cash are operating cash flow and bank borrowings. The Company's cash flow is highly dependent on oil and gas prices. The Company has entered into hedging agreements covering approximately 90%, 75% and 10% of its anticipated production from proved reserves for 2003, 2004 and 2005, respectively. Decreases in prices and lower production at certain properties reduced cash flow sharply in 1998 and 1999 and resulted in a reduction of the Company's borrowing base. Simultaneously, the Company sharply reduced its development and exploration spending. The $111.9 million of capital expenditures for 2002, excluding acquisitions was funded with internal cash flow. The amount expended replaced 222% of production. In the absence of price revisions, net reserves added during the year replaced 160% of production. The $105.0 million 2003 capital budget, which excludes acquisitions, is expected to

increase production and to expand the reserve base. Based on current projections, oil and gas futures prices and the Company's hedge position, the 2003 capital program is expected to be funded with approximately 75% of internal cash flow.

Net cash provided by operations in 2000, 2001 and 2002 was $74.9 million, $129.6 million and $109.2 million, respectively. In 2001, cash flow from operations increased as higher prices and lower interest expense more than offset increasing operating and exploration expenses. In 2002, cash flow from operations decreased with lower prices and volumes, higher exploration and general and administrative costs, somewhat offset by lower interest and direct operating costs.

Net cash used in investing in 2000, 2001 and 2002 was $6.0 million, $78.2 million and $98.7 million, respectively. In 2000, $47.5 million of additions to oil and gas properties were offset by $25.9 million proceeds from sales of assets and $24.8 million of IPF repayments. The 2001 period included $87.0 million of additions to oil and gas properties and $11.6 million of IPF investments, partially offset by $19.0 million of IPF receipts and $3.8 million of asset sales. The 2002 period included $109.1 million of additions to oil and gas properties and $5.1 million of IPF investments partially offset by $17.3 million of IPF receipts. Net cash used in financing (to repay debt) in 2000, 2001 and 2002 was $79.3 million, $50.6 million and $12.6 million, respectively. Historically, sources of financing have been primarily bank borrowings and capital raised through equity and debt offerings. During 2000, recourse debt decreased $45.1 million and total debt (including Trust preferred) decreased $113.5 million. The reduction in debt was the result of applying excess internal cash flow and proceeds from asset sales to debt repayment and exchanges of common stock for fixed income securities. During 2001, recourse debt increased by $5.1 million and total debt (including Trust preferred) decreased by $65.9 million. The reduction in debt was the result of applying excess internal cash flow, proceeds from asset sales and exchanges of common stock for fixed income securities. During 2002, recourse debt increased $20.8 million and total debt (including Trust preferred) decreased by $24.2 million. Recourse debt increased due to the retirement of the IPF credit facility and the repurchase of fixed income securities with borrowing under the Parent credit facility.

Capital Requirements

During 2002, $111.9 million of capital was expended, primarily on development projects. The capital program, excluding acquisitions, was funded with approximately 83% of net cash flow from operations. The Company manages its capital budget with the goal of fully funding it with internal cash flow. The 2003 capital budget of $105.0 million is expected to increase production and expand the reserve base by more than replacing production. Development and exploration activities are highly discretionary, and, for the foreseeable future, management expects such activities to be maintained at levels equal to or below internal cash flow. See "Business—Development and Exploration Activities."

Banking

The Company maintains two separate revolving credit facilities, a $225.0 million Parent facility and a $275.0 million Great Lakes facility (of which 50% is consolidated at Range). In December 2002, the IPF credit facility was retired with borrowings under the Parent credit facility. Each facility is secured by substantially all of the assets of the borrower. The Great Lakes facility is non-recourse to Range. As Great Lakes is 50% owned, half of its borrowings are consolidated in Range's financial statements. Availability under the facilities is subject to borrowing bases set by the banks semi-annually and in certain other circumstances. The borrowing bases are dependent on a number of factors, primarily the lenders' assessment of future cash flows. Redeterminations require approval of 75% of the lenders, increases require unanimous approval. At March 1, 2003, a $147.0 million borrowing base was in effect at Range of which $23.5 million was available and a $205.0 million borrowing base was in effect at Great Lakes, of which $44.0 million was available.

Hedging

Oil and gas prices

The Company regularly enters into hedging agreements to reduce the impact of oil and gas price fluctuations on its operations. The Company's current policy, when futures prices justify, is to hedge between 50% and 75% of projected production on a rolling 12 to 24 month basis. At December 31, 2002, hedges were in place covering 64.6 Bcf of gas at prices averaging $3.96 per mcf and 1.6 million barrels of oil at prices averaging $24.45 per barrel. The hedges fair value, represented by the estimated amount that would be realized or payable on termination, based on contract versus NYMEX prices, approximated a pretax loss of $32.9 million at December 31, 2002. The contracts expire monthly through December 2005 and cover approximately 90% of anticipated 2003 production from proved reserves, 75% of 2004 production and a minor amount of 2005 production. Gains or losses on open and closed hedging transactions are

determined as the difference between the contract price and a reference price, generally closing prices on the NYMEX. Transaction gains and losses are determined monthly and are included as increases or decreases on oil and gas revenues in the period the hedged production is sold. Changes in the value of the ineffective portion of all open hedges is recognized in earnings quarterly. Pretax losses relating to hedging in 2000 and 2001 were $43.2 million and $6.2 million, respectively. A hedging gain of $17.8 million was realized in 2002. Over the last three years, the Company has recorded a cumulative pre-tax hedging loss of $31.6 million. When combined with the $32.9 million unrealized pre-tax loss at year-end 2002, this results in a cumulative net loss of $64.5 million. Since 2001, unrealized gains or losses on hedging positions are recorded at an estimate of fair value based on a comparison of the contract price and a reference price, generally NYMEX, on the Company's Balance sheet as OCI, a component of Stockholders' equity. Due to additional hedging activity and rising prices, the fair value on March 31, 2003 was a loss of $108.7 million.

Interest Rates

At December 31, 2002, the Company had $368.0 million of debt (including Trust preferred) outstanding. Of this amount, $175.7 million bears interest at fixed rates averaging 7.0%. Senior debt and non-recourse debt totaling $192.3 million bears interest at floating rates, which averaged 3.3% at year-end 2002, excluding interest rate swaps. At December 31, 2002, Great Lakes had $100.0 million subject to interest rate swap agreements, of which 50% is consolidated at Range. These swaps consist of five agreements totaling $35.0 million at an average rate of 4.6% which expire in June 2003, two agreements totaling $45.0 million at rates of 7.1% which expire in May 2004 and two agreements of $10.0 million each at an average rate of 2.3% which expire in December 2004. The 30-day LIBOR rate on December 31, 2002 was 1.4%. A 1% increase in short-term interest rates on the floating-rate debt outstanding at December 31, 2002 would cost the Company approximately $1.4 million in additional annual interest, net of swaps.

Capital Restructuring Program

The Company took a number of steps beginning in 1998 to strengthen its financial position. These steps included the sale of assets and the exchange of common stock for fixed income securities. These initiatives have helped reduce Parent company bank debt to $115.8 million and total debt (including Trust preferred) to $368.0 million at December 31, 2002. While the Company believes its financial position has stabilized, management believes its leverage remains too high. The Company believes it should further reduce debt as a percentage of its capitalization. The Company currently believes it has sufficient liquidity and cash flow to meet its obligations for the next 12 months; however, a drop in oil and gas prices or a reduction in production or reserves would reduce the Company's ability to fund capital expenditures and meet its financial obligations.

Inflation and Changes in Prices

The Company's revenues, the value of its assets, its ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in oil and gas prices. Oil and gas prices are subject to significant fluctuations that are beyond the Company's ability to control or predict. During 2002, the Company received an average of $22.25 per barrel of oil and $3.50 per mcf of gas after hedging. Although certain of the Company's costs and expenses are affected by the general inflation, inflation does not normally have a significant effect on the Company. However, industry-specific inflationary pressures built up over an 18-month period in 2000 and 2001 due to favorable conditions in the industry. During 2002, the Company experienced a slight decline in certain drilling and operational costs when compared to the prior year. The Company expects an increase in these costs for 2003. Increases in commodity prices can cause inflationary pressures specific to the industry to also increase.

Results of Operation

	Volumes and Sales Prices		
	2002	2001	2000
Selected operating data			
Average daily production			
Crude oil (per bbl)	5,131	5,250	5,560
NGLs (per bbl)	1,114	893	993
Natural gas (mcfs)	112,592	115,831	112,128
Total (mcfes)	150,061	152,684	151,442
Average sales prices (excluding hedging)			
Crude oil (per bbl)	$23.34	$23.34	$28.15
NGLs (per bbl)	$12.93	$17.33	$18.42
Natural gas (per mcf)	$ 3.02	$ 3.91	$ 3.71
Average sales prices (including hedging)			
Crude oil (per bbl)	$22.25	$25.55	$23.30
NGLs (per bbl)	$12.93	$17.33	$18.42
Natural gas (per mcf)	$ 3.50	$ 3.66	$ 2.90
Total (per mcfe)	$ 3.49	$ 3.75	$ 3.12

The following table identifies certain items included in the results of operation. It is presented to assist in a comparison of the last three years. The table should be read in conjunction with the following discussion of results of operations.

(in thousands)	Year-Ended December 31,		
	2002	2001	2000
Increase (decrease) in revenues			
Write-down of marketable securities	$ (1,220)	$ (1,715)	$ -
Loss on Enron contracts	-	(1,352)	-
Gain/(loss) on asset sales	161	689	(1,116)
Effect of SFAS 133 (commodities)	(2,730)	2,351	-
Hedging gains (losses)	17,790	(6,194)	(43,187)
Recovery from arbitration	715	-	-
	$14,716	$ (6,221)	$ (44,303)
Increase (decrease) in expenses			
Provision for impairment	$ -	$31,085	$ -
General and administration non-cash expense [a]	1,023	(2,410)	3,405
Bad debt expense	150	688	615
Effect of SFAS 133 (interest)	275	1,403	-
Adjustment of IPF valuation allowance	4,240	122	(2,891)
	$ 5,688	$30,888	$ 1,129
Extraordinary Items			
Gain on retirement of debt, net of taxes	$ 2,014	$ 3,951	$ 17,763

(a) Provision for additional G&A representing the mark-to-market expense related to stock held in the deferred compensation plan.

Comparison of 2002 to 2001

Net income in 2002 totaled $25.8 million compared to $17.7 million in 2001. A $4.0 million gain on retirement of securities was realized in 2001 versus $2.0 million in 2002. The 2002 gain was net of deferred taxes of $1.1 million. Production decreased 2% to 150.1 Mmcfe per day due to lower production at Matagorda 519 and other production declines in the Gulf Coast. Revenues of $195.3 million were $24.1 million lower than 2001 due to the production decline and a 7% decrease in average prices to $3.49 per mcfe. The average prices received for oil decreased 13% to $22.25 per barrel and for gas decreased 4% to $3.50 per mcfe. Production expenses decreased $3.0 million to $40.4 million as a result of lower production and property taxes, and reduced workover costs in the Gulf of Mexico. Operating cost per mcfe produced averaged $0.74 in 2002 versus $0.78 in 2001.

Transportation and processing revenues were about the same as 2001 at $3.5 million. IPF's $3.8 million of revenues declined 43% from 2001. IPF records income on payments received on transactions that do not have a valuation allowance. On accounts with a valuation allowance, IPF reduces the carrying value of the receivable. Due to a declining portfolio balance in 2001, less income was recorded from payments received. Due to a significantly lower portfolio balance in 2002, less income was again recorded. During 2001, IPF expenses included $1.8 million of administrative costs, $1.8 million of interest and a net unfavorable adjustment of $122,000 to IPF receivables, net. During 2002, IPF expenses included $1.7 million of administrative costs, $937,000 of interest costs and $4.2 million was added to its valuation allowances.

Exploration expense increased 96% to $11.5 million in 2002 primarily due to higher dry hole cost, additional seismic purchases and personnel expenses. General and administrative expenses increased 41% due to an increase in non-cash mark-to-market compensation expense ($3.4 million), additional personnel costs ($1.4 million), higher insurance costs ($233,000), higher legal and consulting costs ($317,000) offset by lower bad debt expenses. The average number of general and administrative personnel increased 12% between 2001 and 2002.

Other income decreased from income of $490,000 in 2001 to a loss of $2.9 million in 2002. The 2001 period included $2.3 million of ineffective hedging gains and a $689,000 gain on asset sales, partially offset by a $1.7 million write-down of marketable securities and a $1.4 million bad debt expense related to Enron hedges. The 2002 period included a $2.7 million ineffective loss and $1.2 million write-down of marketable securities, offset by a $715,000 recovery on an arbitration. Interest expense decreased 28% to $23.2 million primarily as a result of lower debt balances and falling interest rates. Average outstandings on the Parent credit facility were $90.5 million and $105.3 million for 2001 and 2002, respectively, and the average interest rates were 6.4% and 3.4%, respectively.

Depletion, depreciation and amortization ("DD&A") decreased 1% to $76.8 million as a result of lower production and the mix of production between depletion pools offset by higher depletion rates. The DD&A rate per mcfe in 2002 was $1.40, a $0.01 increase from 2001. The DD&A rate is determined based on year-end reserves (based on NYMEX futures prices averaging $4.11 per mcf and $23.36 per barrel) and the net book value associated with them and to a lesser extent, depreciation on other assets owned. The DD&A rate in the fourth quarter of 2002 was $1.44 per mcfe, reflecting year-end 2002 reserves. The Company currently estimates that the DD&A rate for 2003 will remain at roughly $1.44 per mcfe.

The Company recorded a $31.1 million provision for impairment on acreage and proved properties at year-end 2001. No impairment was recorded in 2002.

Comparison of 2001 to 2000

Net income in 2001 totaled $17.7 million compared to $36.6 million in 2000. A $17.8 million gain on retirement of securities was realized in 2000 versus $4.0 million in 2001. The fourth quarter of 2001 included an impairment charge of $31.1 million. Production increased to 152.7 Mmcfe per day, a 1% increase from the prior year. Revenues benefited from a 20% increase in average prices to $3.75 per mcfe. The average price received for oil increased 10% to $25.59 per barrel and for gas increased 26% to $3.65 per mcfe. Production expenses increased $2.9 million to $43.4 million as a result of higher production and property taxes, increased workover costs and slightly higher costs for labor, services and supplies. Operating cost per mcfe produced averaged $0.78 in 2001 versus $0.73 in 2000.

Transportation and processing revenues decreased 35% to $3.4 million due to the impact of the sale of a gas processing plant in mid-2000 and lower NGL prices. IPF's $6.6 million of revenues declined 7% from 2000. IPF records income on payments for transactions that do not have a valuation allowance. On accounts with a valuation allowance, IPF reduces the carrying value of the receivable. Due to a declining portfolio balance in 2001, less income was recorded from payments received. During 2001, IPF expenses included $1.8 million of administrative costs and $1.8 million of interest. In 2001, a favorable adjustment to IPF reserves of $1.8 million, due to favorable prices early in the year, was more than offset by a year-end increase in the valuation allowance of $2.0 million. During 2000, IPF expenses

included $1.5 million of administrative costs and $3.4 million of interest costs. In 2000, a favorable adjustment of $2.9 million was recorded to IPF valuation allowances.

Exploration expense increased 84% to $5.9 million primarily due to additional seismic activity and increased personnel expenses. General and administrative expenses decreased 18% due to a decline in non-cash mark-to-market compensation expense of $5.8 million offset by additional personnel costs ($1.4 million), higher legal and occupancy costs ($1.2 million) and additional costs ($600,000) incurred from having duplicate functions at Great Lakes and Range. The average number of general and administrative personnel increased 15% from 2000 to 2001.

Other income increased from a loss of $722,000 in 2000 to a gain of $490,000 in 2001. The 2001 period included $2.3 million of ineffective hedging gains and a $689,000 gain on asset sales, partially offset by a $1.7 million write-down of marketable securities and a $1.4 million bad debt expense related to Enron hedges. The 2000 period included a $1.1 million loss on asset sales. Interest expense decreased 19% to $32.2 million primarily as a result of lower average outstanding balances and falling interest rates. Average outstandings on the Parent facility were $124.7 million and $90.5 million for 2000 and 2001, respectively, and the average interest rates were 8.8% and 6.4%, respectively.

DD&A increased 16% to $77.6 million as a result of the mix of production between depletion pools and higher depletion rates. The DD&A rate per mcfe in 2001 was $1.39, an $0.18 increase from 2000. The DD&A rate is determined based on year-end reserves (based on futures prices) and the net book value associated with them and to a lesser extent, depreciation on other assets owned. The DD&A rate in the fourth quarter of 2001 was $1.60 per mcfe.

The Company recorded a provision for impairment on acreage of $5.1 million and proved properties for $25.9 million at year-end 2001. In evaluating possible impairment, the Company evaluates acreage on a separate basis from proved properties. Acreage is assessed periodically to determine whether there has been a decline in value. If a decline is indicated, an impairment is recognized. The Company compares the carrying value of its acreage to the assessment of value that could be recovered from sale, farm-out or exploitation. The Company considers other additional information it believes relevant in evaluating the properties' fair value, such as geological assessment of the area, other acreage purchases in the area and the timing of associated drilling. The following acreage was impaired in 2001 for the reasons indicated (in thousands).

Acreage Pool	Reason for Impairment	Amount
Matagorda Island 519	Probability of drilling reduced based on current assessment of risk and cost	$1,704
East/West Cameron	Condemned portion of leasehold through drilling or geologic assessment	708
Offshore Other	Probability of drilling reduced based on current assessment of risk and cost	1,216
East Texas	Condemned portion of leasehold through drilling	825
West Delta 30	Probability of drilling reduced based on current assessment of risk and cost	688
Total		$5,141

The impairment evaluation on proven properties is based on proved reserves and estimated future cash flows, including revenues from anticipated oil and gas production, severance taxes, direct operating expenses and capital costs. The following properties were impaired in 2001 based on analysis of future cash flows (in thousands):

Property Pool	Reason for Impairment	Amount
Matagorda Island 519	Decline in gas price	$14,001
Offshore Other	Decline in gas price	3,302
Gulf Coast Onshore	Decline in gas price	8,542
Oceana	Decline in oil price	99
Total		$25,944

Management Responsibility for Financial Statements

The financial statements have been prepared by management in conformity with generally accepted accounting principles. Management is responsible for the fairness and reliability of the financial statements and other financial data included in this report. In the preparation of the financial statements, it is necessary to make informed estimates and judgments based on currently available information on the effects of certain events and transactions. The Company maintains accounting and other controls which management believes provide reasonable assurance that financial records are reliable, assets are safeguarded and transactions are properly recorded. However, limitations exist in any system of internal control based upon the recognition that the cost of the system should not exceed benefits derived. The Company's independent auditors, KPMG 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.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk. The Company's major market risk is exposure to oil and gas prices. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American gas production. Oil and gas prices have been volatile and unpredictable for many years.

The Company periodically enters hedging arrangements with respect to oil and gas production from proved reserves. Pursuant to these swaps, Range receives a fixed price for its production and pays market prices to the counterparty. Hedging is intended to reduce the impact of oil and gas price fluctuations. Realized gains and losses are generally recognized in oil and gas revenues when the associated production occurs. Starting in 2001, gains or losses on open contracts are recorded either in current period income or Other comprehensive income ("OCI"). The gains and losses realized as a result of hedging are substantially offset in the cash market when the commodity is delivered. Range does not hold or issue derivative instruments for trading purposes.

As of December 31, 2002, Range had oil and gas hedges in place covering 64.6 Bcf of gas and 1.6 million barrels of oil. Their fair value, represented by the estimated amount that would be realized upon termination, based on contract versus NYMEX prices, approximated a net pre-tax loss of $32.9 million at that date. These contracts expire monthly through December 2005 and cover approximately 90%, 75% and 10% of anticipated production from proved reserves for 2003, 2004 and 2005, respectively. Gains or losses on open and closed hedging transactions are determined as the difference between the contract price and a reference price, generally closing prices on the NYMEX. Transaction gains and losses are determined monthly and are included as increases or decreases to oil and gas revenues in the period the hedged production is sold. Any ineffective portion of such hedges is recognized in earnings as it occurs. Net pre-tax losses relating to these derivatives in 2000 and 2001 were $43.2 million and $6.2 million, respectively. A gain of $17.8 million was recorded in 2002. Effective January 1, 2001, the unrealized gains (losses) on these hedging positions were recorded at an estimate of the fair value based on a comparison of the contract price and a reference price, generally NYMEX, on the Company's Balance sheet as OCI, a component of Stockholders' equity.

The Company had hedge agreements with Enron for 22,700 Mmbtus per day, at $3.20 per Mmbtu for the first three contract months of 2002. Based on accounting requirements, the Company recorded an allowance for bad debts at year-end 2001 of $1.4 million, offset by a $318,000 ineffective gain included in 2001 income and $1.0 million gain included in OCI at year-end 2001 related to these amounts due from Enron. The gain included in OCI at year-end 2001 was included in income in the first quarter of 2002. The last of the Enron contracts expired in March 2002.

In 2002, a 10% reduction in oil and gas prices, excluding amounts fixed through hedging transactions, would have reduced revenue by $17.5 million. If oil and gas futures prices at December 31, 2002 had declined by 10%, the unrealized hedging loss at that date would have decreased 95% or $31.3 million.

Interest Rate Risk. At December 31, 2002, the Company had $368.0 million of debt (including Trust preferred) outstanding. Of this amount, $175.70 million bears interest at fixed rates averaging 7.0%. Senior debt and non-recourse debt totaling $192.3 million bears interest at floating rates, excluding interest rate swaps, which averaged 3.4% at that date. At December 31, 2002, Great Lakes had interest

rate swap agreements totaling $100.0 million, 50% of which is consolidated by Range. Five agreements totaling $35.0 million at an average rate of 4.6% expire in June 2003. Two agreements totaling $45.0 million at rates of 7.1% expire in May 2004. Two agreements of $10.0 million each at 2.3% expire in December 2004. On December 31, 2002, the 30-day LIBOR rate was 1.4%. A 1% decrease in short-term interest rates on the floating-rate debt outstanding (net of amounts fixed through hedging transactions) at December 31, 2002 would cost the Company approximately $1.4 million in additional annual interest.

CHANGE IN ACCOUNTANTS

As more fully disclosed in our Form 8-K and Form 10-Q filed by the Company on July 15, 2002, the Company dismissed its auditor, Arthur Andersen LLP, and appointed KPMG LLP ("KPMG"), during 2002.

As more fully disclosed in our 8-K filed by the Company dated March 26, 2003, the Audit Committee of the Board of Directors of the Company dismissed KPMG as its independent auditors on March 26, 2003. The Company notified KPMG of its dismissal on March 26, 2003 and such dismissal became effective on March 26, 2003. On March 26, 2003, the Audit Committee approved the engagement of Ernst & Young LLP ("E&Y") as its independent auditors for the year-ended December 31, 2003. E&Y accepted its appointment as the Company's independent auditors on April 1, 2003. There were no disagreements with either prior accounting firm prior to their dismissal.

FORWARD-LOOKING STATEMENTS

Certain information included in this report, other materials filed or to be filed by the Company with the Securities and Exchange Commission ("SEC"), as well as information included in oral statements or other written statements made or to be made by the Company contain or incorporate by reference certain statements (other than statements of historical fact) that constitute forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. When used herein, the words "budget," "budgeted," "assumes," "should," "goal," "anticipates," "expects," "believes," "seeks," "plans," "estimates," "intends," "projects" or "targets" and similar expressions that convey the uncertainty of future events or outcomes are intended to identify forward-looking statements. Where any forward-looking statement includes a statement of the assumptions or bases underlying such forward-looking statement, we caution that while we believe these assumptions or bases to be reasonable and to be made in good faith, assumed facts or bases almost always vary from actual results and the difference between assumed facts or bases and the actual results could be material, depending on the circumstances. It is important to note that our actual results could differ materially from those projected by such forward-looking statements. Although we believe that the expectations reflected in such forward-looking statements are reasonable and such forward-looking statements are based upon the best data available at the date this report, we cannot assure you that such expectations will prove correct. Factors that could cause our results to differ materially from the results discussed in such forward-looking statements include, but are not limited to, the following: production variance from expectations, volatility of oil and gas prices, hedging results, the need to develop and replace reserves, the substantial capital expenditures required to fund operations, exploration risks, environmental risks, uncertainties about estimates of reserves, competition, litigation, government regulation, political risks, our ability to implement our business strategy, costs and results of drilling new projects, mechanical and other inherent risks associated with oil and gas production, weather, availability of drilling equipment and changes in interest rates. All such forward-looking statements in this document are expressly qualified in their entirety by the cautionary statements in this paragraph, and the Company undertakes no obligation to publicly update or revise any forward-looking statements.

INDEPENDENT AUDITORS' REPORT

TO THE BOARD OF DIRECTORS AND STOCKHOLDERS
RANGE RESOURCES CORPORATION:

We have audited the accompanying consolidated balance sheets of Range Resources Corporation as of December 31, 2001 and 2002, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the years in the three-year period ended December 31, 2002. These consolidated financial statements are the responsibility of Range Resources Corporation's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We did not audit the financial statements of Great Lakes Energy Partners L.L.C., a fifty percent owned consolidated subsidiary (see Note 2), as of December 31, 2002 and for the year then ended, which statements reflect total assets constituting 32 percent and total revenues constituting 27 percent in 2002 of the related consolidated totals. These statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included in Great Lakes Energy Partners L.L.C. for the year-ended December 31, 2002, is based solely on the report of the other auditors.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. 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 and the report of the other auditors provides a reasonable basis for our opinion.

In our opinion, based on our audits and the report of the other auditors, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Range Resources Corporation as of December 31, 2001 and 2002, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the financial statements, effective January 1, 2001, the Company changed their method of accounting for derivative financial instruments and hedging activities.

KPMG LLP

Dallas, Texas
March 4, 2003

REPORT OF INDEPENDENT AUDITORS

TO THE MANAGEMENT COMMITTEE OF
GREAT LAKES ENERGY PARTNERS, L.L.C.

We have audited the consolidated balance sheets of Great Lakes Energy Partners, L.L.C. and subsidiaries, (a Delaware limited liability company) (the Company) as of December 31, 2002, and the related consolidated statements of income, members' equity, accumulated other comprehensive income (loss) and comprehensive income (loss) and cash flows for the year then ended (not presented separately, herein). These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audit. The financial statements of Great Lakes Energy Partners, L.L.C. as of December 31, 2001 and for the years ended December 31, 2000 and 2001, were audited by other auditors whose report dated September 17, 2002, expressed an unqualified opinion on those statements, included explanatory paragraphs that disclosed the change in the Company's method of accounting for derivative financial instruments and that the Company had restated its consolidated financial statements from inception (September 30, 1999) to December 31, 1999 and the years ended December 31, 2000 and 2001, which consolidated financial statements were previously audited by other independent auditors, who have ceased operations.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Great Lakes Energy Partners, L.L.C and subsidiaries as of December 31, 2002 and the consolidated results of their operations and their cash flows for year then ended in conformity with accounting principles generally accepted in the United States.

ERNST & YOUNG LLP

Pittsburgh, Pennsylvania
January 31, 2003

CONSOLIDATED BALANCE SHEETS

(In thousands)	December 31, 2002	2001
Assets		
Current assets		
Cash and equivalents	$ 1,334	$ 3,380
Accounts receivable	26,832	25,295
IPF receivables, net (Note 2)	6,100	7,000
Unrealized derivative gain (Note 7)	4	37,165
Inventory and other	3,084	4,895
	37,354	77,735
IPF receivables, net (Note 2)	18,351	34,402
Unrealized derivative gain (Note 7)	13	14,936
Oil and gas properties, successful efforts method (Note 16)	1,154,549	1,047,629
Accumulated depletion	(590,143)	(514,272)
	564,406	533,357
Transportation and field assets (Note 2)	34,143	31,288
Accumulated depreciation	(16,071)	(13,108)
	18,072	18,180
Deferred tax asset, net (Note 13)	15,785	-
Other (Note 2)	4,503	3,852
	$658,484	$682,462
Liabilities and Stockholders' Equity		
Current liabilities		
Accounts payable	$ 27,044	$ 27,202
Accrued liabilities	9,678	10,257
Accrued interest	4,449	5,244
Unrealized derivative loss (Note 7)	26,035	397
	67,206	43,100
Senior debt (Note 6)	115,800	95,000
Non-recourse debt (Note 6)	76,500	98,801
Subordinated notes (Note 6)	90,901	108,690
Trust preferred – mandatorily redeemable securities of subsidiary (Note 6)	84,840	89,740
Deferred tax credits, net (Note 13)	-	4,496
Unrealized derivative loss (Note 7)	9,079	2,235
Deferred compensation liability (Note 11)	8,049	4,779
Commitments and contingencies (Note 8)		
Stockholders' equity (Notes 5, 9 and 10)		
Preferred stock, $1 par, 10,000,000 shares authorized, none issued or outstanding	-	-
Common stock, $.01 par, 100,000,000 shares authorized, 54,991,611 and 52,643,275 issued and outstanding, respectively	550	526
Capital in excess of par value	391,082	378,426
Stock held by employee benefit trust, 1,324,537 and 1,038,242 shares, respectively, at cost (Note 11)	(6,188)	(4,890)
Retained earnings (deficit)	(158,059)	(183,825)
Deferred compensation expense	(125)	(139)
Other comprehensive income (loss) (Note 2)	(21,151)	45,523
	206,109	235,621
	$658,484	$682,462

See accompanying notes.

RANGE RESOURCES CORPORATION — 2002

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands, except per share data)	Year-Ended December 31,		
	2002	2001	2000
Revenues			
Oil and gas sales	$ 190,954	$ 208,854	$ 173,082
Transportation and processing	3,495	3,435	5,306
IPF income (Note 2)	3,789	6,646	7,162
Other	(2,900)	490	(722)
	195,338	219,425	184,828
Expenses			
Direct operating	40,443	43,430	40,552
IPF	6,847	3,761	1,974
Exploration	11,525	5,879	3,187
General and administrative (Note 11)	17,240	12,212	14,953
Interest expense and dividends on trust preferred	23,153	32,179	39,953
Depletion, depreciation and amortization	76,820	77,573	66,968
Provision for impairment (Note 2)	-	31,085	-
	176,028	206,119	167,587
Pre-tax income	19,310	13,306	17,241
Income tax (benefit) (Note 13)			
Current	(4)	(406)	(1,574)
Deferred	(4,438)	-	-
	(4,442)	(406)	(1,574)
Income before extraordinary item	23,752	13,712	18,815
Gain on retirement of debt securities, net of taxes (Note 18)	2,014	3,951	17,763
Net income	25,766	17,663	36,578
Gain on retirement of preferred stock	-	556	5,966
Preferred dividends	-	(10)	(1,554)
Net income available to common shareholders	$ 25,766	$ 18,209	$ 40,990
Comprehensive income (loss) (Note 2)	$ (40,908)	$ 63,825	$ 35,750
Earnings per share (Note 14)			
Before extraordinary item - basic	$ 0.45	$ 0.28	$ 0.55
- diluted	$ 0.44	$ 0.28	$ 0.54
After extraordinary item - basic	$ 0.49	$ 0.36	$ 0.97
- diluted	$ 0.47	$ 0.36	$ 0.96

See accompanying notes.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)	Year-Ended December 31,		
	2002	2001	2000
Cash flow from operations			
Net income	$ 25,766	$ 17,663	$ 36,578
Adjustments to reconcile net income to net cash provided by operations:			
Depletion, depreciation and amortization	76,820	77,573	66,968
Deferred income taxes	(3,353)	-	-
Write-down of marketable securities	1,220	1,715	-
Unrealized hedging (gains) losses	3,005	(1,019)	-
Provision for impairment	-	31,085	-
Allowance for bad debts	150	2,040	615
Allowance for IPF receivables	4,240	122	(2,891)
Amortization of deferred issuance costs	899	1,961	2,020
Deferred compensation adjustments	3,306	(68)	4,549
Gain on retirement of securities	(3,125)	(4,004)	(17,978)
(Gain) loss on sale of assets	(161)	(689)	1,116
Changes in working capital			
Accounts receivable	(2,685)	5,540	(6,568)
Inventory and other	(893)	226	(522)
Accounts payable	3,364	548	(5,627)
Accrued liabilities and other	639	(3,095)	(3,381)
Net cash provided by operations	109,192	129,598	74,879
Cash flow from investing			
Oil and gas properties	(109,066)	(87,034)	(47,474)
Field service assets	(2,815)	(2,331)	(2,263)
IPF investments	(5,106)	(11,629)	(6,985)
IPF repayments	17,321	19,034	24,764
Asset sales	996	3,771	25,944
Net cash used in investing	(98,670)	(78,189)	(6,014)
Cash flow from financing			
Net decrease in parent facility and non-recourse debt	(1,501)	(9,108)	(79,611)
Other debt repayment	(11,087)	(42,938)	-
Preferred dividends	-	(10)	(1,444)
Debt issuances fees	(984)	-	-
Issuance of common stock	1,004	1,488	1,798
Repurchase of preferred stock	-	(73)	
Net cash used in financing	(12,568)	(50,641)	(79,257)
Change in cash	(2,046)	768	(10,392)
Cash and equivalents, beginning of year	3,380	2,612	13,004
Cash and equivalents, end of year	$ 1,334	$ 3,380	$ 2,612

See accompanying notes.

RANGE RESOURCES CORPORATION — 2002

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY

(in thousands)	Preferred Stock Shares	Preferred Stock Par Value	Common Stock Shares	Common Stock Par Value	Deferred Compensation Expense	Capital in Excess of Par Par Value	Stock held by Employee Benefit Trust	Retained Earnings (Deficit)	Other Comprehensive Income	Total
Balance December 31, 1999	1,150	$ 1,150	37,902	$ 379	$ (69)	$ 341,177	$ (3,086)	$ (236,502)	$ 189	$ 103,238
Preferred dividends	-	-	-	-	-	-	-	(1,554)	-	(1,554)
Issuance of common	-	-	974	10	(11)	3,115	(410)	-	-	2,704
Conversion of securities	(930)	(930)	10,312	103	-	20,633	-	-	-	19,806
Other comprehensive income	-	-	-	-	-	-	-	-	(828)	(828)
Net income	-	-	-	-	-	-	-	36,578	-	36,578
Balance December 31, 2000	220	220	49,188	492	(80)	364,925	(3,496)	(201,478)	(639)	159,944
Preferred dividends	-	-	-	-	-	-	-	(10)	-	(10)
Issuance of common	-	-	858	8	(59)	4,030	(1,394)	-	-	2,585
Conversion of securities	(220)	(220)	2,597	26	-	9,471	-	-	-	9,277
Other comprehensive income	-	-	-	-	-	-	-	-	46,162	46,162
Net income	-	-	-	-	-	-	-	17,663	-	17,663
Balance December 31, 2001	-	-	52,643	526	(139)	378,426	(4,890)	(183,825)	45,523	235,621
Issuance of common	-	-	717	7	14	4,313	(1,298)	-	-	3,036
Conversion of securities	-	-	1,632	17	-	8,343	-	-	-	8,360
Other comprehensive income	-	-	-	-	-	-	-	-	(66,674)	(66,674)
Net income	-	-	-	-	-	-	-	25,766	-	25,766
Balance December 31, 2002	-	-	54,992	$ 550	$ (125)	$ 391,082	$ (6,188)	$ (158,059)	$ (21,151)	$ 206,109

See accompanying notes.

(1) ORGANIZATION AND NATURE OF BUSINESS

The Company is engaged in the development, acquisition and exploration of oil and gas properties primarily in the Southwestern, Gulf Coast and Appalachian regions of the United States. The Company also provides financing to smaller oil and gas producers through a wholly owned subsidiary, Independent Producer Finance ("IPF"). The Company seeks to increase its reserves and production primarily through development and exploratory drilling and acquisitions. In 1999, Range and FirstEnergy Corp. ("FirstEnergy") contributed their Appalachian oil and gas properties to an equally owned joint venture, Great Lakes Energy Partners L.L.C. ("Great Lakes").

(2) SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The accompanying consolidated financial statements include the accounts of the Company, wholly owned subsidiaries and a 50% pro rata share of the assets, liabilities, income and expenses of Great Lakes. Liquid investments with original maturities of 90 days or less are considered cash equivalents. The Company has no off-balance sheet assets or liabilities other than those referred to in the consolidated financial statements.

Revenue Recognition

The Company recognizes revenues from the sale of products and services in the period delivered. Payments received at IPF relating to return are recognized as income; remaining receipts reduce receivables. Although receivables are concentrated in the oil industry, the Company does not view this as unusual credit risk. However, IPF's receivables are from small independent operators who usually have limited access to capital, and the assets which underlie the receivables lack diversification. Therefore, operational risk is substantial and there is significant risk that required maintenance and repairs, development and planned exploitation may be delayed or not accomplished. A decrease in oil prices could cause an increase in IPF's valuation allowances and a corresponding decrease in income. At December 31, 2002 and 2001, IPF had valuation allowances of $12.6 million and $13.0 million, respectively. The Company had other allowances for doubtful accounts relating to its exploration and production business of $835,000 and $2.9 million at December 31, 2002 and 2001, respectively.

Marketable Securities

The Company has adopted Statement of Financial Accounting Standards No. 115, "Accounting for Certain Investments," ("SFAS 115") pursuant to which the holdings of equity securities qualify as available-for-sale and are recorded at fair value. Unrealized gains and losses are reflected in Stockholders' equity as a component of Other comprehensive income (loss). A decline in the market value of a security below cost deemed other than temporary is charged to earnings. Realized gains and losses are reflected in income. The Company owns approximately 18% of a very small publicly traded independent exploration and production company. This entity has experienced growing difficulties, operationally and financially. During 2002 and 2001, the Company determined that the decline in the market value of an equity security it holds was other than temporary and losses of $1.2 million and $1.7 million, respectively, were recorded as reductions to Other revenues. Based on its analysis of the investment and its assessment of the prospects of realizing any value on the stock, the Company determined that the investment had no determinable value at June 30, 2002 and the book value of the investment was fully reserved. In October 2002, several creditors sought to place this entity in involuntary bankruptcy.

Independent Producer Finance

IPF acquires dollar denominated royalties in oil and gas properties from small producers. The royalties are accounted for as receivables because the investment is recovered from a percentage of revenues until a specified rate of return is received. Payments received believed to relate to the return is recognized as income; remaining receipts reduce receivables. No interest income is recorded on impaired receivables and any payments received applicable to impaired receivables are applied as a reduction of the receivable. Receivables classified as current represent the return of capital expected to be received within 12 months. All receivables are evaluated quarterly and provisions for uncollectible amounts are established based on the Company's valuation of its royalty interest in the oil and gas properties. As of December 31, 2002, receivables for which no valuation allowance existed totaled $12.2 million and the weighted average rate of return on that balance was 17%. Due to favorable oil and gas prices during the last nine months of 2000 and the first six months of 2001, certain of these receivables began to generate all or a greater than anticipated cash flow that favorably impacted the valuation of the receivables. As a result, $1.8 million of increases in receivables were recorded as a reduction in IPF expenses in 2001. However, because of lower prices and lower anticipated cash flows, IPF increased its reserve allowance by $2.0 million in the fourth quarter of 2001. During 2002 and 2001, IPF expenses were comprised of $1.7 million and $1.8 million of general and administrative costs and $937,000 and $1.8 million of interest, respectively. In 2000, IPF recorded a $2.9 million favorable adjustment to their valuation allowance. In 2002 and 2001, IPF recorded a $4.2 million and $2.0 million unfavorable adjustment to their valuation allowance, respectively. Based on the decline in the

performance of the assets underlying the IPF receivables, $4.2 million was added to the valuation allowance in 2002. The valuation allowance at December 31, 2002 and 2001 was $12.6 million and $13.0 million, respectively.

The following table describes the activity for the past three years included in the IPF valuation allowance:

(in thousands)	2002	2001	2000
Balance at beginning of year	$ (12,928)	$ (10,927)	$ (14,513)
Provisions charged to IPF expenses	(5,317)	(4,361)	(6,113)
Recoveries credited to IPF expenses	1,077	2,360	9,004
Amounts written off to principal	4,528	-	695
Balance at year-end	$ (12,640)	$ (12,928)	$ (10,927)

Oil and Gas Properties

The Company follows the successful efforts method of accounting. Exploratory drilling costs are capitalized pending determination of whether a well is successful. Wells subsequently determined to be dry holes are charged to expense. Costs resulting in exploratory discoveries and all development costs, whether successful or not, are capitalized. Geological and geophysical costs, delay rentals and unsuccessful exploratory wells are expensed. Depletion is provided on the unit-of-production method. Oil is converted to gas equivalent basis ("mcfe") at the rate of six mcf per barrel. The depletion, depreciation and amortization ("DD&A") rates were $1.40, $1.39 and $1.21 per mcfe in 2002, 2001 and 2000, respectively. Unproved properties had a net book value of $19.0 million, $25.7 million and $49.5 million at December 31, 2002, 2001 and 2000, respectively. Unproved properties are reviewed each period for impairment and reduced to fair value if required.

The Company adopted Statements of Financial Accounting Standards No. 144 "Accounting for Impairment or Disposal of Long-Lived Assets" ("SFAS 144") on January 1, 2002, and there was no material impact on the Company. The Company's long-lived assets are reviewed for impairment quarterly for events or changes in circumstances that indicate that the carrying amount of an asset may not be recoverable in accordance with SFAS No. 144. Long-lived assets are reviewed for potential impairments at the lowest level for which there are identifiable cash flows that are largely independent of other groups of assets. The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on management's plans to continue to produce and develop proved reserves. Expected future cash flow from the sale of production of reserves is calculated based on estimated future prices. Management estimates prices based upon market-related information including published futures prices. In years where market information is not available, prices are escalated for inflation. The estimated future level of production is based on assumptions surrounding future levels of prices and costs, field decline rates, market demand and supply, and the economic and regulatory climates. When the carrying value exceeds such cash flows, an impairment loss is recognized for the difference between the estimated fair market value and the carrying value of the assets.

The following acreage was impaired in 2001 for the reasons indicated:

Property	Reason for Impairment	Impairment Amount
		(in thousands)
Matagorda Island 519	Probability of drilling reduced based on current assessment of risk and cost/cost overruns and delays	$ 1,704
West Delta 30	Probability of drilling reduced based on current assessment of risk and cost	688
East/West Cameron	Condemned portion of leasehold through drilling or geologic assessment	708
Offshore Other	Probability of drilling reduced based on current assessment of risk and cost	1,216
East Texas	Condemned portion of leasehold through drilling	825
Total		$ 5,141

The following are the proved property values impaired, due to declines in gas prices, in 2001 based on the analysis of estimated future cash flows:

Property	Reason for Impairment	Impairment Amount
		(in thousands)
Matagorda Island 519	Decline in gas price	$ 14,001
Offshore Other	Decline in gas price	3,302
Gulf Coast Onshore	Decline in gas price	8,542
Oceana	Decline in gas price	99
Total		$ 25,944

Transportation, Processing and Field Assets

The Company's gas gathering systems are generally located in proximity to certain of its principal fields. Depreciation on these systems is provided on the straight-line method based on estimated useful lives of 10 to 15 years. The Company sold its only remaining gas processing facility in June 2000. The Company receives third-party income for providing certain field services which are recognized as earned. Depreciation on the associated assets is calculated on the straight-line method based on estimated useful lives ranging from five to seven years. Buildings are depreciated over 10 to 15 years.

Other Assets

The expenses of issuing debt are capitalized and included in other assets on the balance sheet. These costs are generally amortized over the expected life of the related securities (using the sum-of-the year's digits amortization method which does not differ materially from the effective interest method). When a security is retired prior to maturity, related unamortized costs are expensed. At December 31, 2002, such deferred financing costs totaled $3.0 million. Other assets at December 31, 2002 include $3.0 million unamortized debt issuance costs, $1.0 million of marketable securities held in the deferred compensation plan and $403,000 of long-term deposits.

Gas Imbalances

The Company uses the sales method to account for gas imbalances, recognizing revenue based on cash received rather than gas produced. Gas imbalances at December 31, 2001 and December 31, 2002 were not significant. However, the Company has recorded a net liability of $218,000 at December 31, 2002 for those wells where there are insufficient reserves to retire the imbalances.

Stock Options

The Company applies the intrinsic value-based method of accounting prescribed by Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations, in accounting for its fixed plan stock options. As such, compensation expense would be recorded on the date of grant only if the current market price of the underlying stock exceeded the exercise price. SFAS No. 123, Accounting for Stock-Based Compensation, established accounting and disclosure requirements using a fair value-based method of accounting for stock-based employee compensation plans. As allowed by SFAS No. 123, the Company has elected to continue to apply the intrinsic value-based method of accounting described above, and has adopted the disclosure requirements of SFAS No. 123, as amended by SFAS No. 148, Accounting for Stock-Based Compensation-Transition and Disclosures, which are included in Note 10 to the Consolidated financial statements.

Derivative Financial Instruments and Hedging

Beginning in 2001, Statement of Financial Accounting Standards No. 133 "Accounting for Derivatives" ("SFAS 133") required that derivatives be recorded on the balance sheet as assets or liabilities at fair value. For derivatives qualifying as hedges, the effective portion of any changes in fair value is recognized in Stockholders' equity as Other comprehensive income (loss) ("OCI") and then reclassified to earnings when the transaction is consummated. Changes in the value of the ineffective portion of all open hedges is recognized in earnings quarterly. On adopting SFAS 133 in January 2001, the Company recorded a $72.1 million net unrealized pre-tax hedging loss on its balance sheet and an offsetting deficit in OCI. At December 31, 2002, this loss had become $32.9 million by year-end. SFAS 133 can greatly increase volatility of earnings and stockholders' equity of independent oil companies which have active hedging programs such as

Range. Earnings are affected by the ineffective portion of a hedge contract (changes in realized prices that do not match the changes in the hedge price). Ineffective gains or losses are recorded in Other revenue while the hedge contract is open and may increase or reverse until settlement of the contract. Stockholders' equity is affected by the increase or decrease in OCI. Typically, when oil and gas prices increase, OCI decreases. The reduction in OCI at December 31, 2002 related to increases in oil and gas prices since December 31, 2001. Of the $32.9 million unrealized pre-tax loss at December 31, 2002, $24.4 million of losses would be reclassified to earnings over the next 12-month period and $8.5 million for the periods thereafter, if prices remained constant. Actual amounts that will be reclassified will vary as a result of changes in prices.

The Company had hedge agreements with Enron North America Corp. ("Enron") for 22,700 Mmbtu per day, at $3.20 per Mmbtu covering the first three contract months of 2002. Based on accounting requirements, the Company recorded an allowance for bad debts at year-end 2001 of $1.4 million, offset by a $318,000 ineffective gain included in 2001 income and $1.0 million gain included in OCI at year-end 2001 due to Enron's collapse. The gain included in OCI at year-end 2001 was included in income in the first quarter of 2002. The last Enron contracts expired in March 2002.

The Company enters into hedging agreements to reduce the impact of volatile oil and gas prices. These contracts generally qualify as cash flow hedges, however, certain of the contracts have an ineffective portion (changes in realized prices that do not match the changes in hedge price) which is recognized in earnings. Prior to 2001, gains and losses were determined monthly and included in oil and gas revenues in the period the hedged production was sold. Starting in 2001, gains or losses on open contracts are recorded in OCI. The Company also enters into swap agreements to reduce the risk of changing interest rates. These agreements generally qualify as cash flow hedges whereby changes in the fair value of the swaps are reflected as an adjustment to OCI to the extent the swaps are effective and are recognized in income as an adjustment to interest expense in the period covered.

Comprehensive Income

The Company follows Statement of Financial Accounting Standards No. 130, "Reporting Comprehensive Income," defined as changes in Stockholders' equity from non-owner sources. The following is a calculation of comprehensive income (loss) for each of the three years ended December 31, 2002:

(in thousands)	Year-Ended December 31,		
	2002	2001	2000
Net income	$ 25,766	$17,663	$36,578
Cumulative effect of change in accounting principle [a]	-	(72,100)	-
Net amount reclassed to earnings	17,790	(6,194)	-
Change in unrealized hedging gain (losses), net	(83,792)	122,853	-
Unrealized gain (loss) from available-for-sale securities	-	931	(828)
Defaulted hedge contracts, net [b]	(672)	672	-
Comprehensive income (loss)	$(40,908)	$63,825	$35,750

(a) On adopting SFAS 133 on January 1, 2001, the Company recorded a $72.1 million liability for an unrealized pre-tax hedging loss on its balance sheet and an offsetting deficit in Other comprehensive income (loss).

(b) Includes $1.0 million gain related to amounts due from Enron.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported assets, liabilities, revenues and expenses, as well as disclosure of contingent assets and liabilities. Actual results could differ from those estimates. Estimates which may significantly impact the Company's financial statements include reserves, impairment tests on oil and gas properties, IPF valuation allowance and fair value of derivatives.

Recent Accounting Pronouncements

On September 11, 2002, the Emerging Issues Task Force issued EITF Issue No. 02-15, Determining Whether Certain Conversions of Convertible Debt to Equity Securities are within the Scope of FASB Statement No. 84 "Induced Conversions of Convertible Debt." Statement No. 84 was issued to amend APB Opinion No. 26, "Early Extinguishment of Debt" to exclude from its scope convertible debt that is converted to equity securities of the debtor pursuant to conversion privileges different from those included in the terms of the debt at issuance, and the change in conversion privileges is effective for a limited period of time, involves additional consideration, and is made to induce conversion. Statement 84 applies only to conversions that both (a) occur pursuant to changed conversion privileges that are exercisable only for a limited period of time and (b) include the issuance of all of the equity securities issuable pursuant to conversion privileges included in the terms of the debt at issuance for each debt instrument that is converted. The Task Force reached a consensus that Statement 84 applies to all conversions that both (a) occur pursuant to changed conversion privileges that are exercisable only for a period of time and (b) include the issuance of all of the equity securities issuable pursuant to conversion privileges included in the terms of the debt at issuance for each debt instrument that is converted regardless of the party that initiates the offer. This consensus should be applied prospectively to debt conversions completed after September 11, 2002. Since, 1999, the Company has retired 6% Debentures and Trust Preferred securities, each of which are convertible into common stock under the terms of the issue, by either purchasing securities for cash or issuing common stock in exchange for such securities. Since the exchanges of common stock for these convertible debt securities were at relative market values, the convertible securities were retired at a substantial discount to face value. Under the provisions of SFAS No. 84, when an inducement is issued to retire convertible debt, the face value of the convertible debt security shall be charged to Stockholders' equity (common stock and paid in capital), the shares of common stock issued in excess of the shares that would have been issued under the terms of the debt instrument are expensed at the market value of such shares and an offsetting increase to paid in capital. Therefore, instead of recording gains on retirements of such securities acquired at substantial discounts to face value, an expense will be recorded. There will be no difference in total Stockholders' equity from the change in methods of recording the transactions. The Company intends to continue to consider exchanging debt securities for common stock of the Company, despite the negative impact on its financial statements. If, in the opinion of management, the transaction is favorable for the Company and its shareholders, the transaction will be executed despite the negative impact on the financial statements.

In April 2002, the FASB issued Statement of Financial Accounting Standards No. 145 "Rescission of FASB Statements No. 4, 44 and 64, amendment of FASB Statement 13 and Technical corrections ("SFAS 145")." Extinguishment of debt will be accounted for in accordance with Accounting Principles Board Opinion No. 30 "Reporting the Results of Operations, Reporting the Effects of Disposal of a Segment of a Business and Extraordinary, Unusual and Infrequently Occurring Events and Transactions." SFAS 145 has a dual effective date. The provisions relating to accounting for leases were applicable to transactions occurring after May 15, 2002. The provisions relating to the early extinguishment of debt will be adopted by the Company on January 1, 2003. As a result, gains from early extinguishment of debt, which are currently reported as extraordinary items, will be reported in income from continuing operations in comparative financial statements subsequent to the adoption of SFAS 145.

In June 2001, FASB issued Statement of Financial Accounting Standards No. 143 "Asset Retirement Obligations" ("SFAS 143") establishing a new accounting model for the recognition of retirement obligations associated with tangible long-lived assets and requiring that retirement cost should be capitalized as part of an asset's cost and subsequently systematically expensed. The Company will adopt SFAS 143 on January 1, 2003 as required. The adoption of this statement will result in a cumulative effect and be reported as a change in accounting principle relating to the abandonment of oil and gas producing facilities. The Company cannot reasonably quantify the effect of the adoption on either its financial position or results of operations at this time.

In June 2002, the FASB issued Statement of Financial Accounting Standards No. 146 "Accounting for Exit or Disposal Activities ("SFAS 146"). SFAS 146 will be effective for exit or disposal activities that are initiated after December 31, 2002.

Reclassifications

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

(3) ACQUISITIONS

Acquisitions are accounted for as purchases. Purchase prices were allocated to acquired assets and assumed liabilities based on their estimated fair value at acquisition. Acquisitions have been funded with internal cash flow, bank borrowings and the issuance of debt and equity securities. The Company purchased various properties for consideration of $21.8 million, $9.5 million and $4.7 million, during the years ended December 31, 2002, 2001 and 2000, respectively. These purchases include $15.6 million, $4.2 million and $1.7 million for proved oil and gas reserves, respectively. The remainder represents unproved acreage purchases.

(4) DISPOSITIONS

In June 2000, the Company sold a gas plant for $19.7 million and recorded a $716,000 loss.
The following table presents unaudited pro forma operating results as if the sale of the gas plant had occurred on January 1, 2000:

(in thousands, except per share data)	Pro Forma Year-Ended December 31, 2000
Revenues	$182,683
Net income	36,879
Earnings per share – basic and diluted	0.98
Total assets	669,179
Stockholders' equity	157,063

The pro forma results have been prepared for comparative purposes only. They do not purport to present actual results that would have been achieved or to be indicative of future results.

(5) SUPPLEMENTAL CASH FLOW INFORMATION

(in thousands)	Year-ended December 31,		
	2002	2001	2000
Non-cash investing and financing activities:			
Common stock issued			
Under benefit plans	$ 3,092	$ 2,174	$ 983
Exchange for fixed income securities	8,359	14,222	37,086
In payment of preferred dividends	-	-	110
Cash used in (provided by) operating activities:			
Income taxes paid (refunded)	(96)	14	(355)
Interest paid	23,277	31,207	42,192

The Company has and will continue to consider exchanging common stock or equity-linked securities for debt, despite the negative impact on its financial statements due to SFAS 84 (see Note 2 "Recent Accounting Pronouncements"). If, in the opinion of management, the transaction is favorable for the Company and its shareholders, the transaction will be executed. Existing stockholders may be materially diluted if substantial exchanges are consummated. The extent of dilution will depend on the number of shares and price at which common stock is issued, the price at which newly issued securities are convertible and the price at which debt is acquired.

(6) INDEBTEDNESS

The Company had the following debt and Trust preferred (as herein defined) outstanding as of the dates shown. Interest rates, excluding the impact of interest rate swaps, at December 31, 2002 are shown parenthetically:

(in thousands)	December 31,	
	2002	2001
Senior debt		
Parent credit facility (3.4%)	$115,800	$ 95,000
Non-recourse debt		
Great Lakes credit facility (3.2%)	76,500	75,001
IPF credit facility	-	23,800
	76,500	98,801
Subordinated debt		
8.75% Senior Subordinated Notes due 2007	69,281	79,115
6% Convertible Subordinated Debentures due 2007	21,620	29,575
	90,901	108,690
Total debt	283,201	302,491
Trust preferred – mandatorily redeemable securities of subsidiary	84,840	89,740
Total	$368,041	$392,231

From January 1, 2003 to March 1, 2003, the Company exchanged an additional $880,000 face amount of the 6% Debentures for 129,000 shares of common stock and repurchased for cash $400,000 face value of $5.75% Trust preferred. The recording of 6% Debenture exchange includes an inducement expense of $465,000. Interest paid in cash during the years ended December 31, 2002 and 2001 totaled $23.3 million and $31.2 million, respectively. No interest expense was capitalized during 2002, 2001 and 2000.

Parent senior debt

In May 2002, the Company entered into an amended $225 million secured revolving bank facility (the "Parent Facility"). The Parent Facility provides for a borrowing base subject to redeterminations in April and October. On December 31, 2002, the borrowing base on the Parent Facility was $147.0 million, of which $31.1 million was available. On March 1, 2003, the borrowing base on the Parent Facility was $147.0 million of which $23.5 million was available. Redeterminations are based on a variety of factors, including banks' projection of future cash flows. Redeterminations require approval by 75% of the lenders; redeterminations which result in an increase require 100% approval. The Company has the right to increase the borrowing base by up to $10.0 million during any six-month borrowing base period based on a percentage of the fair value of subordinated debt (8.75% Senior subordinated notes, 6% Convertible subordinated debentures or Trust preferred) retired by the Company. Interest is payable the earlier of quarterly or as LIBOR notes mature. The loan matures in July 2005. A commitment fee is paid quarterly on the undrawn balance at an annual rate of 0.25% to 0.50%. The interest rate on the Parent Facility is LIBOR plus 1.50% to 2.25%, depending on outstandings. At December 31, 2002, the commitment fee was 0.375% and the interest rate margin was 0.75%. The weighted average interest rates on the Parent Facility was 3.9% and 6.4% for the years ended December 31, 2002 and 2001, respectively. As of March 1, 2003, the interest rate was 3.4%.

Non-recourse debt

The Company consolidates its proportionate share of borrowings on Great Lakes' $275.0 million secured revolving bank facility (the "Great Lakes Facility"). The Great Lakes Facility is non-recourse to Range and provides for a borrowing base, which is subject to semi-annual redeterminations in April and October. Cash distributions to members of the joint venture are limited by a covenant contained in the Great Lakes Facility. As of December 31, 2002, the borrowing base was $205.0 million of which $52.0 million was available. There is an agreement between the parties of the joint venture that Great Lakes will distribute, on a quarterly basis, amounts deemed to be a tax distribution. This amount, net to the Company, was $3.2 million in 2002 and is estimated to be $4.5 million in 2003. As of December 31, 2002, $25.1 million was available for distribution to members. On March 1, 2003, the borrowing base was $205.0 million of which $44.0 million was available. Interest is payable the earlier of quarterly or as LIBOR notes mature. The loan matures in January 2005. The

interest rate on the facility is LIBOR plus 1.50% to 2.00%, depending on outstandings. A commitment fee is paid quarterly on the undrawn balance at an annual rate of 0.25% to 0.50%. At December 31, 2002, the commitment fee was 0.375% and the interest rate margin was 1.50%. The weighted average interest rates on these borrowings, excluding interest rate hedges, were 3.9% and 6.4% for the years ended December 31, 2002 and 2001, respectively. After hedging, the effective rate was 6.8% and 9.4% for the years ended December 31, 2002 and 2001, respectively. At March 1, 2003, the interest rate was 3.3%, excluding interest rate hedges and 5.5% including interest rate hedges.

IPF had a $100.0 million secured revolving credit facility (the "IPF Facility"). In late December 2002, the $12.9 million balance of the IPF Facility was retired with borrowings from the Parent Facility and the facility was terminated. The IPF Facility was non-recourse to Range. The IPF Facility bore interest at LIBOR plus 1.75% to 2.25% depending on outstandings. Interest expense attributable to the IPF Facility is included in IPF expenses in the Consolidated statements of operations and amounted to $937,000 and $1.8 million for the years ended December 31, 2002 and 2001, respectively. A commitment fee was paid quarterly on the undrawn balance at an annual rate of 0.375% to 0.50%.

Subordinated notes

The 8.75% Senior Subordinated Notes due 2007 (the "8.75% Notes") are redeemable at 104.375% of principal, declining 1.46% each January 15 to par in 2005. The 8.75% Notes are unsecured general obligations subordinated to senior debt. The 8.75% Notes are guaranteed on a senior subordinated basis by the Company's subsidiaries. Interest is payable semi-annually in January and July. During the year ended December 31, 2001, the Company repurchased $42.5 million face amount of the 8.75% Notes at a discount. The cash flow reflects a $41.2 million repayment of debt relating to these repurchases. The Company also exchanged $3.4 million of the 8.75% Notes for common stock. During 2002, the Company repurchased $9.0 million face amount of the 8.75% Notes for $8.9 million. The Company also exchanged $875,000 of the 8.75% Notes for common stock. Exchanges are not reflected on the cash flow statement. The gain on these repurchases is included as an extraordinary Gain on retirement of debt securities on the Consolidated statements of operations. The repurchased notes are held in treasury and may be reissued. As of March 1, 2003, $69.3 million of the 8.75% Notes remained outstanding.

The 6% Convertible Subordinated Debentures Due 2007 (the "6% Debentures") are convertible into common stock at the option of the holder at any time at a price of $19.25 per share. Interest is payable semi-annually in February and August. The 6% Debentures mature in 2007 and are currently redeemable at 103.0% of principal, declining 0.5% each February to 101% in 2006, remaining at that level until it becomes par at maturity. The 6% Debentures are unsecured general obligations subordinated to all senior indebtedness, including the 8.75% Notes for $8.9 million. During 2002 and 2001, $7.1 million and $5.7 million of 6% Debentures were retired at a discount in exchange for 1.2 million and 759,000 shares of common stock, respectively. In addition, $815,000 and $2.3 million were repurchased in 2002 and 2001, respectively. Exchanges are not reflected on the cash flow statement. Extraordinary gains of $1.3 million and $1.9 million were recorded in 2002 and 2001, respectively. Subsequent to December 31, 2002, the Company exchanged for 129,000 shares of common stock an additional $880,000 face amount of the 6% Debentures. As of March 1, 2003, $20.7 million of the 6% Debentures remained outstanding.

Trust Preferred – mandatorily redeemable securities of subsidiary

In 1997, a special purpose affiliate, (the "Trust") issued $120 million of 5.75% Trust Convertible Preferred Securities (the "Trust Preferred"), represented by 2,400,000 shares of Trust Preferred priced at $50 a share. The Trust Preferred is convertible into common stock at a price of $23.50 per share. The Trust invested the proceeds in 5.75% convertible junior subordinated debentures issued by the Company (the "Junior Debentures"), its sole asset. The Junior Debentures and the Trust Preferred mature in November 2027. At December 31, 2001, the Junior Debentures and the related Trust Preferred are redeemable in whole or in part at 102.875% of principal declining 0.58% each November to par in 2007. The Company guarantees payments on the Trust Preferred only to the extent the Trust has funds available. Such guarantee, taken together with other obligations, provides a full subordinated guarantee of the Trust Preferred. The Company has the right to suspend distributions on the Trust Preferred for five years without triggering a default. During such suspension, accumulated distributions accrue additional interest at a rate of 5.75% per annum. The accounts of the Trust are included in the consolidated financial statements after eliminations. Distributions are recorded as interest expense in the Statement of operations, are deductible for tax purposes, and are subject to limitations in the Parent facility as described below. During the year ended December 31, 2002, $2.4 million of Trust Preferred was reacquired at a discount in exchange for 283,000 shares of common stock. In addition $2.5 million face value was repurchased at a cost of $1.5 million. An extraordinary gain of $1.8 million was recorded in 2002. During the year

ended December 31, 2001, $2.9 million of Trust Preferred was reacquired at a discount in exchange for 291,000 shares of common stock. In addition, $50,000 of Trust Preferred were repurchased. An extraordinary gain of $1.2 million was recorded in 2001. Subsequent to December 31, 2002, the Company repurchased $400,000 face value of the Trust Preferred for $236,000. The exchange transactions are not reflected on the cash flow statement because no cash was involved. As of March 1, 2003, $84.4 million of the Trust Preferred remained outstanding.

The debt agreements contain covenants relating to net worth, working capital, dividends and financial ratios. If certain ratio requirements are not met, payments of interest on the Trust Preferred would be restricted. The Parent facility allows the payment of common dividends on common stock, beginning January 1, 2003. The Company (including Great Lakes) was in compliance with all such covenants at December 31, 2002. Under the most restrictive covenant, $803,000 of dividends or other restricted payments could be paid at December 31, 2002.

Following is the principal maturity schedule for the long-term debt outstanding as of December 31, 2002:

YEAR-ENDING DECEMBER 31,	*(in thousands)*
2003	$ -
2004	-
2005	192,300
2006	-
2007	90,901
2008	-
Thereafter	84,840
	$ 368,041

(7) FINANCIAL INSTRUMENTS AND HEDGING ACTIVITIES

The Company's financial instruments include cash and equivalents, receivables, payables, debt and commodity and interest rate derivatives. The book value of cash and equivalents, receivables and payables are considered to be representative of fair value because of their short maturity. The book value of bank borrowings is believed to approximate fair value because of their floating rate structure.

A portion of future oil and gas sales is periodically hedged through the use of option or swap contracts. Realized gains and losses on these instruments are reflected in the contract month being hedged as an adjustment to oil and gas revenue. At times, the Company seeks to manage interest rate risk on its credit facilities through the use of swaps. Gains and losses on these swaps are included as an adjustment to interest expense in the relevant periods.

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

(in thousands)	DECEMBER 31, 2002		DECEMBER 31, 2001	
	Book Value	Fair Value	Book Value	Fair Value
Assets				
Cash and equivalents	$ 1,334	$ 1,334	$ 3,380	$ 3,380
Marketable securities	1,040	1,040	2,323	2,323
Commodity swaps	17	17	52,101	52,101
Total	2,391	2,391	57,804	57,804
Liabilities				
Commodity swaps	(32,964)	(32,964)	-	-
Interest rate swaps	(2,150)	(2,150)	(2,632)	(2,632)
Long-term debt [a]	(283,201)	(279,894)	(302,491)	(292,028)
Trust Preferred [a]	(84,840)	(52,177)	(89,740)	(50,254)
Total	(403,155)	(367,185)	(394,863)	(344,914)
Net financial instruments	$(400,764)	$(364,794)	$(337,059)	$(287,110)

(a) Fair Value based on quotes received from certain brokerage houses. Quotes for December 31, 2002 were 101.0% for the 8.75% Notes, 81.5% for the 6% Debentures and 61.5% for the 5.75% Trust Preferred.

At December 31, 2002, the Company had open hedging contracts covering 64.6 Bcf of gas at prices averaging $3.96 per mcf and 1.6 million barrels of oil at prices averaging $24.45 barrel. Their fair value, represented by the estimated amount that would be realized upon termination, based on contract versus New York Mercantile Exchange ("NYMEX") price, approximated a net unrealized pre-tax loss of $32.9 million at December 31, 2002. These contracts expire monthly through December 2005. Gains or losses on open and closed hedging transactions are determined as the difference between the contract price and the reference price, generally closing prices on the NYMEX. Transaction gains and losses are determined monthly and are included as increases or decreases to oil and gas revenues in the period the hedged production is sold. Due to additional hedging activity and rising prices, the Company estimates the net unrealized loss at March 1, 2003 was $108.7 million. Net pre-tax losses incurred relating to these derivatives for the years ended December 31, 2000 and 2001 were $43.2 million and $6.2 million, respectively. A hedging gain of $17.8 million was realized in 2002. These hedging positions are recorded on the Company's balance sheet at an estimate of fair value based on a comparison of the contract price and a reference price, generally NYMEX. Other revenues in the Consolidated statement of operations were decreased for ineffective hedging losses of $2.7 million and $1.1 million in the year-ended December 31, 2002 and 2001, respectively.

The Company had hedge agreements with Enron for 22,700 Mmbtu per day, at $3.20 per Mmbtu for the first three months of 2002. Based on accounting requirements, the Company had recorded an allowance for bad debts at year-end 2001 of $1.4 million, offset by a $318,000 ineffective gain included in 2001 income and $1.0 million gain included in OCI at year-end 2001 related to these amounts due from Enron. The gain included in OCI at year-end 2001 was included in income in the first quarter of 2002. The last of the Enron contracts expired as of March 2002.

The following schedule shows the effect of the closed oil and gas hedges since January 1, 2001 and the value of open contracts at December 31, 2002:

(in thousands)	Quarter Ended	Hedging Gain (Loss)
Closed Contracts – 2001	March 31, 2001	$ (23,440)
	June 30, 2001	(5,250)
	September 30, 2001	8,450
	December 31, 2001	14,047
		(6,193)
2002	March 31, 2002	11,726
	June 30, 2002	3,639
	September 30, 2002	3,484
	December 31, 2002	(1,059)
		17,790
Total realized gain		$ 11,597
Open Contracts – 2003	March 31, 2003	$ (8,570)
	June 30, 2003	(6,302)
	September 30, 2003	(4,839)
	December 31, 2003	(4,714)
		(24,425)
2004	March 31, 2004	(3,584)
	June 30, 2004	(2,098)
	September 30, 2004	(1,326)
	December 31, 2004	(1,055)
		(8,063)
2005	March 31, 2005	(280)
	June 30, 2005	(107)
	September 30, 2005	(53)
	December 31, 2005	(19)
		(459)
Total unrealized loss		(32,947)
Total realized and unrealized loss		$ (21,350)

Interest rate swap agreements are accounted for on the accrual basis. Through Great Lakes, the Company uses interest rate swap agreements to manage the risk that future cash flows associated with interest payments on amounts outstanding under the variable rate Great Lakes facility may be adversely affected by volatility in market interest rates. Under the Company's interest rate swap agreements, the Company agrees to pay an amount equal to a specified fixed rate of interest times a notional principal amount, and to receive in return, a specified variable rate of interest times the same notional principal amount. Changes in the fair value of the Company's interest rate swaps, which qualify for cash flow hedge accounting treatment are reflected as adjustments to Other comprehensive income to the extent the swaps are effective and will be recognized as an adjustment to interest expense during the period in which the cash flows related to the Company's interest payments are made. The ineffective portion of the changes in fair value of the Company's interest rate swaps is recorded in income in the period incurred. At December 31, 2002, Great Lakes had interest rate swap agreements totaling $100.0 million, 50% of which is consolidated at Range. These swaps consist of five agreements totaling $35.0 million at an average rate of 4.6% which expire in June 2003, two agreements totaling $45.0 million at rates of 7.1% which expire in May 2004 and two agreements of $10.0 million each at rates of 2.3% which expire in December 2004. Range's share of the fair value of the swaps at December 31, 2002, was a hedge liability of $2.1 million based on current quotes. On December 31, 2002, the 30-day LIBOR rate was 1.4%. The Company recognized additional interest expense of $2.4 million, $1.1 million and $85,000 due to interest swaps in 2002, 2001 and 2000, respectively.

The combined fair value of net losses on oil and gas hedges and net losses on interest rate swaps totaling $35.1 million appeared as Unrealized derivative gains and Unrealized derivative losses on the balance sheet at December 31, 2002. Hedging activities are conducted with major financial or commodities trading institutions which management believes are acceptable credit risks. At times, such risks may be concentrated with certain counterparties. The credit worthiness of these counterparties is subject to continuing review.

(8) COMMITMENTS AND CONTINGENCIES

The Company is involved in various legal actions and claims arising in the ordinary course of business, which includes a royalty owner suit filed in 2000 asking for class action certification against Great Lakes and the Company. 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. During 2002, approximately $250,000 of costs were expensed in defense of litigation and $385,000 reduced an accrued liability related to periods prior to the formation of Great Lakes. The Company received a $715,000 arbitration recovery, net of $72,000 legal costs.

The Company leases certain office space and equipment under cancelable and non-cancelable leases, most of which expire within three years and may be renewed by the Company. Rent expense under such arrangements totaled $1.7 million, $1.7 million and $1.6 million in 2002, 2001 and 2000, respectively. Future minimum rental commitments under non-cancelable leases are as follows:

Year-Ending December 31,	*(in thousands)*
2003	$1,808
2004	1,128
2005	974
2006	561
2007 and thereafter	299
	$4,770

(9) STOCKHOLDERS' EQUITY

The Company has authorized capital stock of 110 million shares which includes 100 million shares of common stock and 10 million shares of preferred stock. In 1995, the Company issued $28.8 million of $2.03 Convertible exchangeable preferred stock which was convertible into common stock at a price of $9.50. The issue was retired in December 2001. The following is a schedule of changes in the number of outstanding common shares since the beginning of 2001:

	Year-Ended December 31,	
	2002	2001
Beginning Balance	52,643,275	49,187,682
Issuances:		
Employee benefit plans	417,661	372,398
Stock options exercised	130,566	223,594
Stock purchase plan	168,500	263,000
Exchange for:		
8.75% Senior notes	182,709	779,960
6% Debentures	1,165,700	758,597
Trust preferred	283,200	291,211
$2.03 Preferred	-	766,889
Other		(56)
	2,348,336	3,455,593
Ending Balance	54,991,611	52,643,275

(10) STOCK OPTION AND PURCHASE PLANS

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

	Inactive			Active			
	Domain Plan	Domain Directors' Plan	1989 Plan	Directors' Plan	1999 Plan	Total	Average Exercise Price
Outstanding at December 31, 1999	558,432	9,670	2,509,690	168,000	60,000	3,305,792	$7.72
Granted	-	-	-	56,000	643,200	699,200	2.12
Exercised	(98,697)	-	(246,575)	(8,000)	-	(353,272)	2.57
Expired/cancelled	(210,770)	(9,670)	(1,080,222)	(80,000)	(38,000)	(1,418,662)	8.58
Outstanding at December 31, 2000	248,965	-	1,182,893	136,000	665,200	2,233,058	6.23
Granted	-	-	-	56,000	774,350	830,350	6.46
Exercised	(111,481)	-	(59,113)	-	(53,000)	(223,594)	1.63
Expired/cancelled	-	-	(581,080)	(72,000)	(71,437)	(724,517)	13.05
Outstanding at December 31, 2001	137,484	-	542,700	120,000	1,315,113	2,115,297	4.47
Granted	-	-	-	48,000	1,438,850	1,486,850	4.89
Exercised	(5,782)	-	(56,157)	(2,000)	(66,627)	(130,566)	2.45
Expired/cancelled	-	-	(32,963)	(14,000)	(142,474)	(189,437)	4.95
Outstanding at December 31, 2002	131,702	-	453,580	152,000	2,544,862	3,282,144	$4.46

There were options exercisable of 975,026 (weighted average price of $4.46), 585,526 (weighted average price of $4.04) and 1,043,452 (weighted average price of $9.32) at December 31, 2002, 2001 and 2000, respectively.

In 1999, shareholders approved the stock option plan (the "1999 Plan") providing for the issuance of options on 1.4 million common shares. In 2001, shareholders approved an increase in the number of options issuable to 3.4 million shares. In May 2002, shareholders approved an increase in the number of options issuable to 6.0 million. All options issued under the 1999 Plan from August 5, 1999 through May 22, 2002 vested 25% per year beginning after one year and had a maximum term of 10 years. Options issued under the 1999 Plan after May 22, 2002 vest 30%, 30% and 40%, over a three-year period and have a maximum term of five years. During the year-ended December 31, 2002, 1,438,850 options were granted under the 1999 Plan at exercise prices of $4.43, $5.26 and $5.49 a share. At December 31, 2002, 2.5 million options were outstanding under the 1999 Plan at exercise prices of $1.94 to $6.67.

The Company maintains the 1989 Stock Option Plan (the "1989 Plan") which authorized the issuance of options on 3.0 million common shares. No options have been granted under this plan since March 1999. Options issued under the 1989 Plan vest 30%, 30% and 40% over a three year period and expire in five years. At December 31, 2002, 453,580 options remained outstanding under the 1989 Plan at exercise prices of $2.63 to $7.62.

In 1994, shareholders approved the Outside Directors' Stock Option Plan (the "Directors' Plan"). In 2000, shareholders approved an increase in the number of options issuable to 300,000, extended the term of the options to 10 years and set the vesting period at 25% per year beginning a year after grant. Effective May 22, 2002, the term of the option was changed to five years with vesting immediately upon grant. Director's options are normally granted upon election of a director or annually upon their re-election at the annual meeting. During the year-ended December 31, 2002, 48,000 options were granted under the Directors' Plan at exercise prices of $5.49 share. At December 31, 2002, 152,000 options were outstanding under the Directors' Plan at exercise prices of $2.81 to $6.00.

The Domain stock option plan was adopted when that company was acquired, with existing Domain options becoming exercisable into Range common stock. No options have been granted under this plan since the acquisition. At December 31, 2002, 131,702 options remained outstanding under the Plan at a price of $3.46 a share.

In total, 3.3 million options were outstanding at December 31, 2002 at exercise prices ranging from $1.94 to $7.62 as follows:

			Inactive		Active		
Range of Exercise price	Average Exercise price	Weighted Average Remaining Life (Yrs)	Domain Plan	1989 Plan	Directors' Plan	1999 Plan	Total
$1.94 - $4.99	$3.36	7.0	131,702	309,655	56,000	1,132,499	1,629,856
$5.00 - $9.99	6.05	6.8	-	143,925	96,000	1,412,363	1,652,288
Total			131,702	453,580	152,000	2,544,862	3,282,144

In 1997, shareholders approved a plan (the "Stock Purchase Plan") authorizing the sale of 900,000 shares of common stock to officers, directors, key employees and consultants. In May 2001, shareholders approved an increase in the number of shares authorized under the Stock Purchase Plan to 1,750,000. Under the Stock Purchase Plan, the right to purchase shares at prices ranging from 50% to 85% of market value may be granted. To date, all purchase rights have been granted at 75% of market. Due to the discount from market value, the Company recorded additional compensation expense of $227,800, $375,000 and $236,000 during 2002, 2001 and 2000, respectively. Through December 31, 2002, 1,289,819 shares have been sold under the Stock Purchase Plan for $5.4 million. At December 31, 2002, rights to purchase 166,500 shares were outstanding with terms expiring in May 2003.

The Company has adopted the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." Accordingly, no compensation cost has been recognized for the stock option plans. Had compensation cost been determined based on the fair value at the grant date for awards in 2002, 2001 and 2000 consistent with the provisions of SFAS No. 123, the Company's net income and earnings per share would have been reduced to the pro forma amounts indicated below:

(in thousands, except per share data)	YEAR-ENDED DECEMBER 31,		
	2002	2001	2000
As reported -			
Net income	$25,766	$17,663	$ 36,578
Earnings per share			
- basic	0.49	0.36	0.97
- diluted	0.47	0.36	0.96
Stock-based employee compensation cost (income) net of taxes included in the determination of net income as reported	$ 2,149	$ (44)	$ 2,957
Pro forma -			
Net income	$24,846	$16,877	$36,412
Earnings per share			
- basic	0.47	0.35	0.97
- diluted	0.46	0.34	0.95
Stock based employee compensation cost, net of taxes, that would have been included in the determination of net income if the fair value based method had been applied	$ 920	$ 786	$ 166

The fair value of each option grant on the date of grant for the disclosures is estimated by using the Black-Scholes option pricing model with the following weighted-average assumptions used for 2002, 2001 and 2000, respectively: fair value of $4.89, $6.50 and $2.14 per share; dividend yields of $0 per share; expected volatility factors of, 166.19, 69.80 and 64.89; risk-free interest rates of 4.9%, 5.0% and 5.5%, and an average expected life of nine years, six years and six years.

(11) DEFERRED COMPENSATION

In 1996, the Board of Directors of the Company adopted a deferred compensation plan (the "Plan"). The Plan gives certain senior employees the ability to defer all or a portion of their salaries and bonuses and invest in common stock of the Company or make other investments at the employee's discretion. The stock held in the employee benefit trust is treated in a manner similar to treasury stock with an offsetting amount reflected as a deferred compensation liability of the Company and the carrying value of the deferred compensation is adjusted to fair value each reporting period by a charge or credit to operations in the general and administrative expense category on the Company's Statement of operations. The Company recorded mark-to-market expenses related to deferred compensation of $1.1 million in 2002, a benefit of $2.4 million in 2001, and an expense of $3.4 million in 2000.

(12) BENEFIT PLAN

The Company maintains a 401(k) Plan for its employees. The Plan permits employees to contribute up to 50% of their salary (subject to Internal Revenue limitations) on a pre-tax basis. Historically, the Company has made discretionary contributions to the 401(k) Plan annually. All Company contributions become fully vested after the individual employee has three years of service with the Company. In 2002, 2001 and 2000, the Company contributed $602,000, $554,000 and $483,000, at then market value, respectively, of the Company's common stock to the 401(k) Plan. The Company does not require that employees hold the contributed stock in their account. Employees have a variety of investment options available in the 401(k) Plan. Employees are encouraged to diversify out of Company stock based on their personal investment strategy.

(13) INCOME TAXES

The Company's federal income tax benefit for the years ended December 31, 2002, 2001 and 2000, was ($3.4 million), ($406,000) and ($1.6 million), respectively. A reconciliation between the statutory federal income tax rate and the Company's effective federal income tax rate is as follows:

(in thousands)	Year-Ended December 31,		
	2002	2001	2000
Statutory tax rate	35%	35%	34%
Gain on retirement of securities	6	10	34
Permanent differences	(1)	1	11
Valuation allowance	(63)	(45)	(88)
State	1	(1)	(6)
Other	4	(4)	(14)
Effective tax rate	(18)%	(4)%	(29)%
Income taxes paid (refunded)	($96)	$14	($355)

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

(in thousands)	December 31,	
	2002	2001
Deferred tax assets		
Net operating loss carryover	$ 71,661	$ 53,977
Allowance for doubtful accounts	4,717	7,035
Percentage depletion carryover	5,256	5,256
Net unrealized loss on hedging	11,388	-
AMT credits and other	665	660
Total deferred tax assets	93,687	66,928
Deferred tax liabilities		
Depreciation	(77,902)	(54,732)
Unrealized gain on hedging	-	(16,692)
Net deferred tax assets (liabilities)	$15,785	$(4,496)

A valuation allowance on the net deferred tax asset was originally established (in years prior to 2000) due to the uncertainty of whether future taxable income would be sufficient to utilize it. Increased oil and gas prices in early 2001 allowed the reversal of the valuation allowance during the first half of 2001. Therefore, income taxes were recorded at a statutory rate for financial reporting in the second and third quarters of 2001. Due to the Company's tax loss carryover, percentage depletion carryover and AMT credits, such statutory taxes were deferred. However, due to the property impairments recorded in the fourth quarter of 2001, taxes recorded earlier in the year were reversed and no statutory provision for taxes was required in 2001. A deferred tax liability of $4.5 million is recorded on the balance sheet at year-end 2001. Without considering the tax effects of certain deferred hedging gains included in Other comprehensive income (loss) at December 31, 2001, deferred tax assets exceeded deferred tax liabilities by $12.2 million, at December 31, 2001. The inclusion of deferred tax liabilities related to OCI caused the deferred tax liabilities to exceed deferred tax assets by the amount recorded on the balance sheet and accordingly, the valuation allowance on the deferred tax asset was reversed in 2001 through a reduction of $6.1 million and an increase to OCI of $12.2 million. During 2002, the $12.2 million valuation allowance included in OCI at December 31, 2001 was

reversed as the related hedge positions closed as an $11.2 million reduction of 2002 income tax expense, an $18,000 adjustment of prior-period estimates and a $960,000 increase to Capital in excess of par value. The $960,000 increase to Capital in excess of par value relates to the tax benefits of employer stock option plans. At December 31, 2002, deferred tax assets exceeded deferred tax liabilities by $15.7 million with $11.4 million of deferred tax assets related to deferred hedging losses included in OCI. Based on the Company's recent profitability and its current outlook, no valuation allowance was deemed necessary at December 31, 2002.

At December 31, 2002, the Company had regular net operating loss ("NOL") carryovers of $218.2 million and alternative minimum tax ("AMT") NOL carryovers of $198.5 million that expire between 2003 and 2022. Regular NOLs generally offset taxable income and to such extent, no income tax payments are required. To the extent that AMT NOLs offset AMT income, no alternative minimum tax payment is due. NOLs generated prior to a change-of-control are subject to limitations. The Company experienced several change-of-control events between 1994 and 1998 due to acquisitions. Consequently the use of $34.1 million of NOLs is limited to $10.2 million per year. Remaining NOLs are not limited. At December 31, 2002, the Company had a statutory depletion carryover of $6.6 million and AMT credit carryovers of $665,000 that are not subject to limitation or expiration.

The following table sets forth the year of expiration of NOL (pre-tax) carryovers which generate the largest component of the deferred tax assets listed above:

(in thousands)	NOL Carryover Amount	
Expiration	Regular	AMT
2003	$ 488	$ 422
2004	666	136
2005	522	353
2006	396	277
Thereafter	216,153	197,315
Total	$218,225	$198,503

(14) EARNINGS (LOSS) PER COMMON SHARE

The following table sets forth the computation of basic and diluted earnings per common share:

(in thousands except per share amounts)	Year-Ended December 31,		
	2002	2001	2000
Numerator:			
Income before extraordinary item	$ 23,752	$ 13,712	$ 18,815
Gain on retirement of preferred stock	-	556	5,966
Preferred dividends	-	(10)	(1,554)
Numerator for earnings per share, before extraordinary item	23,752	14,258	23,227
Extraordinary item			
Gain on retirement of securities, net	2,014	3,951	17,763
Numerator for earnings per share, basic and diluted	$ 25,766	$ 18,209	$ 40,990
Denominator:			
Weighted average shares	54,283	51,159	42,882
Stock held by employee benefit trust	(1,213)	(1,002)	(767)
Weighted average shares - basic	53,070	50,157	42,115
Stock held by employee benefit trust	1,213	1,002	767
Dilutive potential common shares stock options	135	106	50
Denominator for diluted earnings per share	54,418	51,265	42,932
Earnings per share basic and diluted:			
Before extraordinary gain			
Basic	$ 0.45	$ 0.28	$ 0.55
Diluted	$ 0.44	$ 0.28	$ 0.54
Extraordinary gain			
Basic	$ 0.04	$ 0.08	$ 0.42
Diluted	$ 0.03	$ 0.08	$ 0.42
After extraordinary gain			
Basic	$ 0.49	$ 0.36	$ 0.97
Diluted	$ 0.47	$ 0.36	$ 0.96

During 2002 and 2001, 160,000 and 129,000 stock options were included in the computation of diluted earnings per share. All remaining stock options, the 6% Debentures, Trust Preferred and the $2.03 Preferred were not included because their inclusion would have been antidilutive.

(15) MAJOR CUSTOMERS

The Company markets its production on a competitive basis. Gas is sold under various types of contracts ranging from life-of-the-well to short-term contracts that are cancelable within 30 days. Oil purchasers may be changed on 30 days notice. The price for oil is generally equal to a posted price set by major purchasers in the area. The Company sells to oil purchasers on the basis of price and service. For each of the years ended December 31, 2002, 2001 and 2000, three customers accounted for 10% or more of total oil and gas revenues and the combined sales to those three customers accounted for 35%, 50% and 50% of total oil and gas revenues, respectively. Management believes that the loss of any one customer would not have a material long-term adverse effect on the Company.

From the inception of the Great Lakes joint venture through June 30, 2001, Great Lakes sold approximately 90% of its gas production to FirstEnergy, at prices based on the close of NYMEX each month plus a basis differential. Effective July 1, 2001, Great Lakes began selling its gas to several different companies, including FirstEnergy. In the year-ended December 31, 2002, approximately 92% of Great Lakes gas was sold at prices based on the close of NYMEX contracts each month plus a basis differential. The remainder is sold at a fixed price.

(16) OIL AND GAS ACTIVITIES

The following summarizes selected information with respect to producing activities. Exploration costs include capitalized as well as expensed outlays:

(in thousands)	Year-Ended December 31,		
	2002	2001	2000
Oil and gas properties:			
Properties subject to depletion	$1,135,590	$1,021,898	$947,526
Unproved properties	18,959	25,731	49,523
Total	1,154,549	1,047,629	997,049
Accumulated depletion	(590,143)	(514,272)	(443,876)
Net	$ 564,406	$ 533,357	$553,173
Costs incurred:			
Acquisition [a]	$ 21,790	$ 9,489	$ 4,701
Development	66,284	69,162	46,032
Exploration [b]	23,232	11,405	4,498
Total	$ 111,306	$ 90,056	$ 55,231

(a) Includes $15,643, $4,227 and $1,719 for oil and gas reserves, respectively; the remainder represents acreage purchases.

(b) Includes $11,525, $5,879 and $3,187 of exploration cost expensed in 2002, 2001 and 2000, respectively.

(17) INVESTMENT IN GREAT LAKES

The Company owns 50% of Great Lakes and consolidates its proportionate interest in the joint venture's assets, liabilities, revenues and expenses. The following table summarizes the 50% interest in Great Lakes' audited financial statements as of or for the years ended December 31, 2002 and 2001:

(in thousands)	Year-Ended December 31,	
	2002	2001
Balance Sheet:		
Current assets	$ 8,356	$ 15,954
Oil and gas properties, net	185,233	168,090
Transportation and field assets, net	15,428	15,645
Other assets	117	110
Current liabilities	16,607	9,674
Long-term debt	76,500	75,000
Members' equity	111,550	117,413
Statement of operations:		
Revenues	$ 54,310	$ 52,735
Direct operating expense	7,996	8,413
Exploration expense	2,434	2,026
G&A expense	1,758	1,838
Interest expense	5,353	8,284
DD&A	14,258	12,182
Pre-tax income	20,403	17,735

With respect to certain revenue and expense items, derived from the Company's 50% interest in Great Lakes, the Company makes certain reclassifications to the above items primarily related to transportation and gathering.

(18) EXTRAORDINARY ITEM

During 2000, 5.7 million shares of common stock were exchanged for $25.0 million of Trust preferred and $13.8 million of 6% Debentures. During 2001, 1.8 million shares of common stock were exchanged for $2.9 million of Trust preferred, $5.7 million of 6% Debentures and $3.4 million of 8.75% Senior Subordinated Notes. In addition, $50,000 of Trust Preferred, $2.3 million of 6% Debentures and $42.5 million of 8.75% Senior Subordinated Notes were repurchased. During 2002, 1.6 million shares of common stock were exchanged for $2.4 million of Trust Preferred, $7.1 million of 6% Debentures and $875,000 of 8.75% Notes. In addition, $2.5 million of Trust Preferred, $815,000 of 6% Debentures and $9.0 million of 8.75% Notes were repurchased. Since 1998, there have been 15.2 million shares of common stock exchanged for convertible debt and securities in the amount of $95.8 million. In connection with these exchanges, an extraordinary gain net of costs of $3.1 million ($2.0 million net of taxes), $4.0 million and $17.8 million was recorded in 2002, 2001 and 2000, respectively, because the securities were retired at a discount. In addition, 767,000 and 4.6 million shares of common stock were exchanged for $5.4 million and $23.2 million of the $2.03 Preferred during 2001 and 2000, respectively. In 2001, the remaining shares of $2.03 Preferred were repurchased for $74,000. The gain on retirement of debt securities was net of taxes of $1.1 million, $0 and $0 in 2002, 2001 and 2000, respectively.

(19) UNAUDITED SUPPLEMENTAL RESERVE INFORMATION

The Company and its 50% pro rata portion of Great Lakes' proved oil and gas reserves are located in the United States. Proved reserves are those quantities of crude oil and natural gas which, based 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.

The following schedules are presented in accordance with SFAS No. 69 ("SFAS 69"), "Disclosures about Oil and Gas Producing Activities," to provide users with a common base for preparing estimates of future cash flows and comparing reserves among companies.

Estimated Net Proved Oil and Natural Gas Reserves – Reserves of crude oil, condensate, natural gas liquids and natural gas are estimated by the Company's engineers and are adjusted to reflect contractual arrangements and royalty rates in effect at the end of each year. Many assumptions and judgmental decisions are required to estimate reserves. Reported quantities are subject to future revisions, some of which may be substantial, as additional information becomes available from: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price changes and other economic factors.

The U.S. Securities and Exchange Commission defines proved reserves as those volumes of crude oil, condensate, natural gas liquids and natural gas that geological and engineering data demonstrate with reasonable certainty are recoverable from known reservoirs under existing economic and operating conditions. Proved undeveloped reserves are volumes expected to be recovered as a result of additional investments for drilling new wells to offset productive units, recompleting existing wells, and/or installing facilities to collect and transport production.

Production quantities shown are net volumes withdrawn from reservoirs. These may differ from sales quantities due to inventory changes, and especially in the case of natural gas, volumes consumed for fuel and/or shrinkage from extraction of natural gas liquids.

SFAS 69 requires calculation of future net cash flows using a 10% annual discount factor and year-end prices, costs and statutory tax rates, except for known future changes such as contracted prices and legislated tax rates. The reported value of proved reserves is not necessarily indicative of either fair market value or present value of future cash flows because prices, costs and governmental policies do not remain static; appropriate discount rates may vary; and extensive judgment is required to estimate the timing of production. Other logical assumptions would likely have resulted in significantly different amounts.

The average prices used at December 31, 2002 to estimate the reserve information were $27.52 per barrel for oil, $18.72 per barrel for natural gas liquids and $4.76 per mcf for gas using the benchmark NYMEX prices of $31.17 per barrel and $4.75 per Mmbtu. The average prices at December 31, 2001 were $17.59 per barrel for oil, $12.38 per barrel for natural gas liquids and $2.70 per mcf for gas using the benchmark NYMEX prices of $20.38 per barrel and $2.63 per Mmbtu.

QUANTITIES OF PROVED RESERVES

	CRUDE OIL AND NGLS	NATURAL GAS	NATURAL GAS EQUIVALENT
	(Mbbls)	(Mmcf)	(Mmcfe)
Balance, December 31, 1999	28,817	443,783	616,685
Revisions	(1,699)	(1,186)	(11,380)
Extensions, discoveries and additions	1,226	26,639	33,995
Purchases	226	1,605	2,961
Sales	(170)	(2,135)	(3,155)
Production	(2,398)	(41,039)	(55,427)
Balance, December 31, 2000	26,002	427,667	583,679
Revisions	(3,359)	(33,575)	(53,728)
Extensions, discoveries and additions	479	31,542	34,414
Purchases	427	5,761	8,325
Sales	(627)	(190)	(3,955)
Production	(2,242)	(42,278)	(55,730)
Balance, December 31, 2001	20,680	388,927	513,005
Revisions	1,707	30,014	40,253
Extensions, discoveries and additions	2,830	45,652	62,635
Purchases	40	18,283	18,526
Sales	(26)	(1,513)	(1,669)
Production	(2,279)	(41,096)	(54,773)
Balance, December 31, 2002	22,952	440,267	577,977
Proved developed reserves			
December 31, 2000	17,215	305,796	409,086
December 31, 2001	14,066	276,162	360,558
December 31, 2002	17,176	320,224	423,280

The "Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves" ("Standardized Measure") is a disclosure requirement of SFAS 69. 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

(in thousands)	As of December 31,		
	2002	2001	2000
Future cash inflows	$2,697,068	$1,397,897	$4,697,062
Future costs:			
Production	(677,214)	(471,144)	(755,727)
Development	(204,137)	(176,799)	(177,070)
Future net cash flows	1,815,717	749,954	3,764,265
Income taxes	(463,980)	(87,745)	(457,996)
Total undiscounted future net cash flows	1,351,737	662,209	3,306,269
10% discount factor	(852,104)	(350,801)	(1,800,007)
Standardized measure	$ 499,633	$ 311,408	$1,506,262

CHANGES IN STANDARDIZED MEASURE

(in thousands)	As of December 31,		
	2002	2001	2000
Standardized measure, beginning of year	$ 311,408	$1,506,262	$ 503,151
Revisions:			
Prices	212,091	(1,076,168)	1,184,950
Quantities	116,757	(8,244)	(89,180)
Estimated future development cost	(31,384)	4,620	36,650
Accretion of discount	39,915	196,426	63,468
Income taxes	(103,529)	114,556	(130,626)
Net revisions	233,850	(768,810)	1,065,262
Purchases	17,815	6,245	8,003
Extensions, discoveries and additions	60,232	25,815	91,855
Production	(150,511)	(165,033)	(134,556)
Sales	(1,605)	(2,967)	(8,525)
Changes in timing and other	28,444	(290,104)	(18,928)
Standardized measure, end of year	$ 499,633	$ 311,408	$1,506,262

DIRECTORS

Robert E. Aikman[2,4] – Chairman, The Aikman Companies
Anthony V. Dub[1] – Chairman, Indigo Capital, LLC
V. Richard Eales[1] – Financial Consultant
Thomas J. Edelman[3] – Chairman, Range Resources
Allen Finkelson[2,3,4] – Partner, Cravath, Swaine & Moore
Jonathan S. Linker[1] – Energy Consultant
Alexander P. Lynch[2,4] – Managing Director, J.P. Morgan
John H. Pinkerton[3] – President, Range Resources

Board Committee Membership:
[1]Audit, [2]Compensation, [3]Executive, and [4]Nomination

SENIOR MANAGEMENT

Thomas J. Edelman – Chairman
John H. Pinkerton – President
Terry W. Carter – Executive Vice President – Exploration and Production
Eddie M. LeBlanc III – Senior Vice President and Chief Financial Officer
Herb A. Newhouse – Senior Vice President – Gulf Coast
Chad L. Stephens – Senior Vice President – Corporate Development
Rodney L. Waller – Senior Vice President and Corporate Secretary

FORM 10-K

Copies of the Company's Annual Report on Form 10-K filed with the Securities and Exchange Commission may be obtained upon request from Investor Relations at our corporate address.

INVESTOR INFORMATION

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www.rangeresources.com

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