

# SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

## Form 10-K

Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

### For the Fiscal Year Ended December 31, 1998

Commission File Number 1-8754

### SWIFT ENERGY COMPANY

(Exact Name of Registrant as Specified in Its Charter)

Texas  
(State of Incorporation)

74-2073055  
(I.R.S. Employer Identification No.)

16825 Northchase Dr., Suite 400  
Houston, Texas 77060  
(281) 874-2700

(Address and telephone number of principal executive offices)

Securities registered pursuant to Section 12(b) of the Act:

| Title of Class:                         | Exchanges on Which Registered:                    |
|---|---|
| Common Stock, par value \$.01 per share | New York Stock Exchange<br>Pacific Stock Exchange |
| Convertible Subordinated Notes Due 2006 | New York Stock Exchange                           |

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

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

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

The aggregate market value of the voting stock held by non-affiliates at March 10, 1999 was approximately \$110,936,000.

The number of shares of common stock outstanding as of December 31, 1998 was 16,291,242 shares of common stock, \$.01 par value.

### Documents Incorporated by Reference

#### Document

#### Incorporated as to

Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 11, 1999

Part III, Items 10, 11, 12, and 13

# Form 10-K

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## Swift Energy Company and Subsidiaries

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(1) Incorporated by reference from Notice and Proxy Statement for the Annual Meeting of Shareholders to be held May 11, 1999.

## PART I

### Items 1 and 2. Business and Properties

See page 12 for explanations of abbreviations and terms used herein.

#### General

Swift Energy Company (the "Company"), a Texas corporation organized in October 1979, is engaged in the exploration, development, acquisition, and operation of oil and gas properties, with a primary focus on U.S. onshore natural gas reserves. As of December 31, 1998, the Company had interests in over 1,750 oil and gas wells located in eight states, of which the Company operated 836 wells representing 91% of its proved reserves base. At such date, the Company had estimated proved reserves of 436.1 Bcfe, of which approximately 81% was natural gas, 55% was proved developed, and 97% was located in both Texas (84%) and Louisiana (13%).

The Company's primary focus is development and exploration drilling in its core areas, the AWP Olmos Field located in South Texas and the Austin Chalk trend in Texas and Louisiana. The AWP Olmos Field is characterized by long-lived reserves, while the Austin Chalk trend is characterized by more short-lived reserves with high initial production and rapid decline rates. These fields accounted for approximately 51% and 42%, respectively, of the Company's proved reserves as of December 31, 1998, and approximately 40% and 48%, respectively, of the Company's production during 1998.

In the third quarter of 1998, the Company purchased the Toledo Bend Properties from Sonat Exploration Company ("Toledo Bend Properties") for approximately \$87.0 million in cash, with approximately \$56.8 million of the total spent for producing properties, approximately \$15.0 million to purchase an interest in two gas processing plants, and approximately \$15.2 million to acquire leasehold properties. This acquisition extended the Company's properties in the Austin Chalk trend, and the Company expects to utilize its operating expertise in this area to successfully develop and exploit these properties. As of December 31, 1998, these properties consisted of 162 producing wells (115 of which were Company operated), 23 saltwater disposal wells, a 20% interest in two natural gas plants, associated production facilities, and interests in 200,875 gross (125,378 net) undeveloped acres and approximately 114,000 undeveloped fee mineral acres. At such date, the estimated proved reserves relating to these acquired properties were 130.5 Bcfe, of which approximately 58% was natural gas and 59% was proved undeveloped. The Company's production on these properties, which began in the third quarter of 1998, amounted to approximately 11.6 Bcfe, of which 44% was natural gas. Such production comprised approximately 30% of the Company's production during 1998.

The Company pursues a balanced growth strategy that includes an active drilling program, strategic acquisitions, and the utilization of advanced technologies. The Company's operating philosophy is to increase its reserves base through both drilling and acquisitions, shifting the balance between the two activities in response to market conditions. Over the last several years, the Company's growth has resulted primarily from its increased acreage position and drilling activities in the AWP Olmos Field and the Austin Chalk trend. Capital expenditures for development and exploration drilling, primarily in the Company's core areas, were \$71.8 million

and \$101.0 million in 1996 and 1997, respectively, while capital expenditures for acquisitions were \$1.5 million and \$8.4 million. The downward pressure on commodity prices during 1998 caused the Company to decrease its originally targeted capital expenditures for drilling and to redirect a portion of those expenditures to the acquisition of producing properties, primarily the above mentioned Toledo Bend Properties. In 1998, development and exploration drilling expenditures for the year, concentrated in the first half of the year, totaled \$67.4 million while \$59.5 million was spent for the acquisition of producing properties, almost all in the third quarter of 1998.

In response to market conditions, the Company has budgeted capital expenditures of only \$54.2 million for 1999, of which \$36.0 million is targeted for drilling, \$31.3 million for development drilling, and \$4.7 million for exploratory drilling. The remaining \$18.2 million is targeted principally for leasehold, seismic, and geological costs of prospects. The Company plans to fund this budget primarily through the use of its internally generated cash flows and limited borrowings under its credit facility. Besides its core areas, the Company is also actively pursuing exploratory and development drilling opportunities in other basins in Texas, Arkansas, Louisiana, Wyoming, and New Zealand.

The Company has increased its proved reserves from 90.1 Bcfe at year-end 1993 to 436.1 Bcfe at year-end 1998, which has resulted in the replacement of 449% of production during the same five-year period. In 1998, the Company increased its proved reserves by 21%, resulting in the replacement of 296% of its 1998 production. The Company's five-year average reserves replacement costs were \$0.88 per Mcfe. As a result of both acquisition and drilling activity, 1998 production increased 54% over 1997 production. Due to economies of scale, geographic concentration, and increased production, general and administrative expenses and production costs have fallen from \$0.44 and \$0.36 per Mcfe, respectively, in 1993 to \$0.10 and \$0.34 per Mcfe in 1998. The combination of increased production and decreased operating costs per Mcfe has resulted in average annual growth in net cash provided by operating activities of 50% per year from year-end 1993 to year-end 1998.

#### Properties

The Company's proved reserves are geographically concentrated, with approximately 93% of the Company's proved reserves at December 31, 1998, attributable to its properties in the AWP Olmos Field and the Austin Chalk trend.

*AWP Olmos Field.* The Company's largest unified operation is located in the AWP Olmos Field in South Texas. The Company has extensive expertise in the AWP Olmos Field and a long history of experience with low-permeability, tight-sand formations typical of this field. Since acquiring its first AWP Olmos Field acreage in 1988, the Company has made detailed studies of drainage patterns in the formation and has introduced innovations in fracture design and implementation methods and coiled tubing technology that substantially reduce overall costs and improve recoveries.

Properties in the AWP Olmos Field represented approximately 51% of the Company's proved reserves at December 31, 1998, and approximately 40% of the Company's 1998 production. At December 31, 1998, the Company owned interests in and was the operator of 447 wells producing natural gas from the Olmos Sand formation

at a depth of approximately 10,000 feet. The Company has engaged in extensive fracturing operations to increase the permeability of the formation and flow of gas from the wells. In addition, the Company has used coiled tubing velocity strings in numerous wells to improve production rates. Also, by utilizing a system of BJ Services, Inc., the Company is able to monitor fracturing operations from its Houston headquarters through direct computer access to the field.

In 1998, the Company drilled 33 (31 successful) development wells in the AWP Olmos Field and three unsuccessful exploratory wells northwest of the field. Of the properties operated by the Company in the AWP Olmos Field, the Company or entities managed by the Company own 100% of the working interests in all but 21 wells in this field, and in these 21 wells the smallest ownership interest is 99%. The Company increased its leasehold position in the field in 1998 by obtaining additional acreage and, if warranted, anticipates acquiring more acreage in the future. The Company's planned 1999 capital expenditures of \$12.0 million in this area will focus on fracture extensions and further use of coiled tubing velocity strings.

*Austin Chalk Trend.* At December 31, 1998, the Company owned drilling and production rights in 596,607 gross acres, 357,588 net acres, and 137,213 fee mineral acres in the Austin Chalk trend containing substantial proved undeveloped reserves. Of this acreage position, 402,560 gross acres, 244,662 net acres, and all 137,213 fee mineral acres were acquired in the Toledo Bend Properties acquisition described above. The Austin Chalk trend represented approximately 42% of the Company's proved reserves at December 31, 1998 and 48% of the Company's production in 1998. The wells in this trend are horizontal wells, primarily producing natural gas in the Texas portion of the trend and producing an approximately even split of oil and natural gas in the Louisiana portion. These wells deliver high initial flow rates and strong initial cash flows that decline rapidly. The Company believes the Austin Chalk reserves complement the Company's long-lived reserves in the AWP Olmos Field. Since 1992, the Company has participated in 78 horizontal wells in the Austin Chalk trend with an 87% success rate, including 16 successful development wells out of 19 drilled and two successful exploratory wells out of four drilled in 1998. The Company believes its success in the Austin Chalk trend is attributable to its ability to identify hydrocarbon-bearing fractures, relying on its expertise in geological and geophysical analyses, and to its ability to drill and operate horizontal wells. The Company anticipates drilling 14 development wells and one exploratory well in the Austin Chalk trend during 1999. The acquisition of seismic data in the Cougar Run and Nimitz areas in Fayette County during 1998 has helped in upgrading locations to drill horizontal wells targeting the Austin Chalk formation determined from previous seismic data acquisitions and subsequent successful drilling in the Rocky Creek and North Fayetteville prospects.

Substantial portions of the Company's property interests in the Austin Chalk trend have been acquired through joint development arrangements with industry partners who are active participants in exploration of the Austin Chalk trend. The first joint venture, with Chesapeake Energy Corporation in 1993 and now completed, covered approximately 8,800 acres in Fayette County, Texas, with the Company currently holding an average working interest of 25%. In September 1995, the Company entered into a joint development agreement with Union Pacific Resources providing for an area of mutual interest (AMI) covering 19,500 gross acres in Fayette County (the North Fayetteville Prospect), with the

Company and UPR alternately serving as operator of any wells drilled on the acreage. During 1996, the Company purchased UPR's interest in 9,500 of these gross acres, and the joint development arrangement was reduced to a 10,000 gross acre block in which the Company has an average working interest of 30% to 35%. This joint venture is now completed. The Company has a 100% working interest in the 9,500 acres it purchased and has drilled three wells on the property.

In 1996, the Company and UPR initiated another joint development arrangement covering approximately 8,000 acres in Washington County, Texas, in which the Company owns a 25% working interest. This joint development area was subsequently expanded to encompass approximately 17,000 gross acres in Washington County. Simultaneously, the Company and UPR entered into two additional joint development agreements, one covering an approximate 6,300 gross acre area in Washington County, in which the Company owns a 50% working interest, and another covering an approximate 8,100 gross acre area in Washington County and Austin County, in which the Company owns a 75% working interest and serves as operator.

In 1997, in a joint venture with Belco Oil and Gas Corporation, the Company acquired a 50% working interest in 20,000 net acres adjoining the North Fayetteville Prospect area, for which Swift serves as operator. Several wells were drilled on this acreage in 1998. Also in 1997, in an adjoining area covering 8,000 gross acres in Fayette County, the Company entered a joint venture with Chesapeake Energy Corporation with a 68% working interest for which the Company serves as the operator. Two wells were drilled on this acreage in 1997, and three wells were drilled in 1998.

In 1998, the Company signed a joint development agreement with Chevron USA Production Company encompassing 144,000 gross acres in central Texas, where the Company and Chevron are participating in the drilling of a number of wells targeted for the Edwards Limestone, Sligo, Austin Chalk, and other formations in the counties of Fayette, Colorado, and Austin. Swift's interests originally covered 68,000 net acres but were subsequently expanded to 70,000 net acres. The Company and Chevron each own an undivided 50% working interest within the AMI, with the Company serving as operator. To date, the Company has drilled two exploratory wells targeting the Austin Chalk trend in this AMI, one of which was successful, and is continuing to acquire acreage in selective areas within the AMI.

### **Exploration and Development Drilling Activities**

In 1991, the Company began an intensive effort to develop an inventory of exploration and development drilling prospects, identifying drilling locations through integrated geological and geophysical studies of the Company's undeveloped acreage and other prospects. As a result, the Company added 118 Bcfe of proved reserves through drilling in 1996 and 120 Bcfe in 1997. In 1998, the Company deferred drilling projects scheduled for the second half of the year in response to market conditions and, accordingly, reserves added by drilling decreased to 73.9 Bcfe. The 1998 additions were a result of the Company's success rate of 87% for development wells (53 out of 61 drilled) and 36% for exploratory wells (5 out of 14 drilled).

The Company's successful drilling program has led to the acquisition of additional acreage during 1997 and 1998 in the areas of its principal operations in the AWP Olmos Field in South Texas and in the Austin Chalk trend, the latter

covering several Texas counties and, as of 1998, two Louisiana parishes.

The Company pursues a "controlled risk" approach to exploratory drilling, focusing its exploration activities on specific U.S. regions in which its technical staff has considerable experience and which are in close proximity to known producing horizons where the potential for significant reserves exists. The Company seeks to minimize its exploration risk by investing in multiple prospects, farming out interests to industry partners and Company-managed drilling funds, utilizing advanced technologies, and drilling in different types of geological formations. The Company utilizes basin studies to analyze targeted formations based on their potential size, risk profile, and economic parameters.

The Company's development strategy is designed to maximize the value and productivity of its existing properties through development drilling and recovery methods, enhancing production results through improved field production techniques, lowering production costs, and applying the Company's technical expertise and resources to exploit producing properties efficiently. The Company utilizes various recovery techniques, which include employing water flooding and acid treatments, fracturing reservoir rock through the injection of high-pressure fluid, and inserting coiled tubing velocity strings to speed gas flow. The Company believes that the application of fracturing technology and coiled tubing has resulted in significant increases in production and decreases in drilling and operating costs, particularly in the Company's AWP Olmos Field.

The Company's exploration and development activities are conducted by its in-house exploration staff, assisted by professionals from other departments, including reservoir engineers, geologists, geophysicists, petrophysicists, landmen, and drilling and production engineers. The Company believes that one of the keys to its success has been its team approach, which integrates multiple disciplines to maximize efficient utilization of information leading to drillable projects.

The Company has increasingly utilized advanced seismic technology to enhance the quality of its drilling efforts, including two-dimensional (2-D) and three-dimensional (3-D) seismic analyses and amplitude versus offset (AVO) studies. During 1997, the Company completed its first international seismic acquisition program in two key areas of its holdings in New Zealand. In the Rimu prospect, Swift acquired a 30-kilometer cross-swath, as well as 2-D seismic data in the Tawa prospect, complementing existing 2-D and 3-D data. It also acquired 21 miles of 2-D data in the AWP Olmos Field in South Texas and 51 miles of data in the Fayette County portion of the Austin Chalk trend. Two more prospects in the North Louisiana Salt Basin were shot in the form of 2-D swaths of approximately 16 miles each. During 1998, the Company performed two additional 2-D acquisitions in Fayette County, Texas. It also conducted a 2-D cross swath that yielded 3-D data in Point Coupee Parish, Louisiana, which resulted in the Company's release of acreage in the area.

In addition to development and exploration activities in the AWP Olmos Field and the Austin Chalk trend, the Company is currently focusing its exploration activities in three main domestic geographical areas: the Gulf Coast Basin, the Wyoming Powder River Basin, and the North

Louisiana Salt Basin. It has also initiated an exploration program in New Zealand.

*Gulf Coast Basin.* The Company defines this area as including all the Texas counties and Louisiana parishes along the Gulf Coast and extending into Mississippi and Alabama and including all target formations present except the Austin Chalk trend and the Olmos sand. In 1998, three successful development wells (out of six) and two successful exploratory wells (out of three) were drilled in the Gulf Coast Basin, following four successful exploratory wells and one successful development well drilled in 1997. In 1999, two exploratory wells and one development well are scheduled for drilling in the Gulf Coast Basin.

During 1997, the Company acquired 1,920 gross acres in Jim Hogg County, in which the Company owns a minimum 75% working interest. A successful exploratory well drilled by the Company to the Queen City formation in 1997 was followed by three successful development wells and a successful exploratory well in 1998. Further work in the area is awaiting a fracture extension program to be carried out in 1999 to assess the field's full potential.

*Wyoming Powder River Basin.* The Minnelusa trend has been the subject of extensive study over several years by the Company's multidisciplinary teams in order to identify the location of stratigraphic hydrocarbon traps. In recent years, the Company has shifted its emphasis to pursue the Cretaceous trend in southern Campbell County and northern Converse County in Wyoming, as well as north into the Williston Basin in Daniels County, Montana. This shift is due to the Company's commitment to find larger reserve accumulations at a lower risk by drilling in areas with multiple producing zones and larger field sizes. In 1997, the Company successfully drilled one out of two exploratory wells in the Minnelusa trend in Campbell County, Wyoming. In 1998, the Company participated in a successful exploratory well in Converse County, Wyoming. A second exploratory well drilled in Daniels County, Montana, was unsuccessful.

*North Louisiana Salt Basin.* The North Louisiana Salt Basin covers the neighboring corners of Arkansas, Louisiana, and Texas ("Ark-La-Tex region"). In this area, the Jurassic Smackover formation, a prolific hydrocarbon producer from multiple levels and from a variety of structures, including fault traps, salt anticlines, basement structures, and stratigraphic traps, is the primary target, and the Haynesville formation is the secondary target. Both formations have been the subject of intense geophysical and geological analyses by the Company for a number of years. During 1998, analyses were completed for two 2-D seismic swaths, each covering 12 miles, that were acquired in 1997 in Lafayette County, Arkansas, and Bossier Parish, Louisiana. Since 1996, Swift has had four successes out of five exploratory wells drilled in the area (the unsuccessful well was drilled in 1998). The Company plans to drill an additional exploratory well in the area in 1999.

*New Zealand.* After several years of preparation, including the acquisition and analyses of seismic data, the Company will drill an exploratory well on its permit to the Mangahewa formation in the Taranaki Basin on the North Island of New Zealand in 1999. In 1998, the Company participated in an unsuccessful exploratory well on a permit in which the Company obtained an interest through Marabella Enterprises Ltd. See "Foreign Activities – New Zealand."

The following table sets forth the results of the Company's drilling activities during the three years ended December 31, 1998:

| Year | Type of Well | Gross Wells |           |     | Net Wells |           |     |
|------|--------------|-------------|-----------|-----|-----------|-----------|-----|
|      |              | Total       | Producing | Dry | Total     | Producing | Dry |
| 1996 | Exploratory  | 11          | 7         | 4   | 5.9       | 3.7       | 2.2 |
|      | Development  | 142         | 134       | 8   | 110.5     | 106.7     | 3.8 |
| 1997 | Exploratory  | 15          | 7         | 8   | 7.2       | 2.7       | 4.5 |
|      | Development  | 167         | 159       | 8   | 127.5     | 123.6     | 3.9 |
| 1998 | Exploratory  | 14          | 5         | 9   | 8.7       | 2.7       | 6.0 |
|      | Development  | 61          | 53        | 8   | 37.7      | 32.8      | 4.9 |

## Operations

The Company generally seeks to be named as operator for wells in which it or its affiliated limited partnerships and joint ventures have acquired a significant interest, although this typically occurs only when they own the major portion of the working interest in a particular well or field. The Company acts as operator of 836 wells at December 31, 1998, which comprise approximately 91% of the Company's total proved reserves.

As operator, the Company is able to exercise substantial influence over development and enhancement of a well and to supervise operation and maintenance activities on a day-to-day basis. The Company does not own the drilling rigs used to drill on properties it operates. Drilling rigs are contracted from independent contractors and supervised by the Company. The Company employs drilling, production, and reservoir engineers, geologists, and other operations and production specialists who strive to improve production rates, increase reserves, and/or lower the cost of operating its oil and gas properties.

Oil and gas properties are customarily operated under the terms of a joint operating agreement, which provides for reimbursement of the operator's direct expenses and monthly per-well supervision fees. Per-well supervision fees vary widely depending on the geographic location and depth of the well, whether the well produces oil or gas, and other factors. Such fees received by the Company in 1998 ranged from \$200 to \$1,632 per well per month.

## Marketing of Production

The Company typically sells its gas production at or near the wellhead, although in some cases it must be gathered by the Company or other operators and delivered to a central point. Gas production is sold in the spot market at prevailing prices. The Company sells its oil production at prevailing market prices. The Company does not refine any oil it produces. During the year ended December 31, 1998, two purchasers accounted for approximately 16% and 10% of the Company's revenues. Three oil or gas purchasers accounted for 10% or more of the Company's revenues during the year ended December 31, 1997, with those purchasers accounting for approximately 42% of revenues in the aggregate. Because of the availability of other purchasers, the Company does not believe that the loss of any single oil or gas purchaser or contract would materially affect its sales.

The Company has entered into gas processing and gas transportation agreements with respect to its natural gas

production in the AWP Olmos Field with Pacific Gas & Electric Corporation and its affiliates ("PG&E") for up to 75,000 Mcf per day. These contracts were recently amended, effective May 1, 1998, to provide for an initial ten-year term, with automatic one-year extensions unless earlier terminated. In addition, the amended contracts provided for more favorable terms benefiting the Company. The Company believes that these arrangements adequately provide for its gas transportation and processing needs in the AWP Olmos Field for the foreseeable future. Additionally, at the discretion of the Company and PG&E, the gas processed and transported under these agreements may be sold to PG&E at monthly indexed prices based upon the current natural gas price.

Much of the Company's Austin Chalk production from Fayette and Washington counties, Texas, is currently dedicated under long-term gas purchase and gas processing contracts with Aquila Southwest Pipeline Corporation ("Aquila"). The Company believes that these contracts adequately provide for the gas purchase and processing needs of its Austin Chalk production, subject to practical limitations inherent in gas field operations. The prices received are redetermined monthly to reflect the current natural gas price.

The Company's oil production from the Toledo Bend Properties is sold to credit-worthy purchasers at prevailing market prices. The Company's gas production from the Toledo Bend Properties is processed under long-term gas processing contracts with Union Pacific Resources Company ("UPR"). Processed liquids and residue gas production are sold in the spot market at prevailing prices. Recently UPR signed a definitive agreement with Duke Energy Field Services, Inc. ("Duke") for the acquisition by Duke of UPR's gas gathering processing and marketing subsidiary, Union Pacific Fuels, Inc. ("UPFI"). Through a merger, UPFI will become a wholly owned subsidiary of Duke. The transaction is expected to close by the end of March 1999. This merger will not affect the contractual obligations between the Company and UPR.

The following table summarizes sales volumes, sales prices, and production cost information for the Company's net oil and gas production for the three-year period ended December 31, 1998. "Net" production is production that is owned by the Company either directly or indirectly through partnerships or joint venture interests and produced to its interest after deducting royalty, limited partner, and other similar interests.

|                                    | Year Ended December 31, |            |            |
|------------------------------------|-------------------------|------------|------------|
|                                    | 1998                    | 1997       | 1996       |
| Net Sales Volume:                  |                         |            |            |
| Oil (Bbls)                         | 1,800,676               | 672,385    | 623,386    |
| Gas (Mcf) <sup>1</sup>             | 28,225,974              | 21,359,434 | 15,696,798 |
| Gas equivalents (Mcf)              | 39,030,030              | 25,393,744 | 19,437,114 |
| Average Sales Price:               |                         |            |            |
| Oil (per Bbl)                      | \$ 11.86                | \$ 17.59   | \$ 19.82   |
| Gas (per Mcf)                      | \$ 2.08                 | \$ 2.68    | \$ 2.57    |
| Average Production Cost (per Mcfe) | \$ 0.34                 | \$ 0.35    | \$ 0.32    |

<sup>1</sup>Natural gas production for 1998, 1997, and 1996 includes 866,232, 1,015,226, and 1,156,361 Mcf, respectively, delivered under the volumetric production payment agreement pursuant to which the Company is obligated to deliver certain monthly quantities of natural gas (see Note 1 to the Company's financial statements).

Under the volumetric production payment entered into in 1992, as of December 31, 1998, the Company has a remaining commitment to deliver approximately 1.1 Bcf of gas meeting certain heating equivalent and quality standards through October 2000, when such agreement expires. Since entering into this agreement, these properties have produced in excess of the required monthly delivery requirements.

### Price Risk Management

The Company's revenues are primarily the result of sales of its oil and natural gas production. Market prices of oil and natural gas may fluctuate and adversely affect operating results. To mitigate some of this risk, the Company engages periodically in certain limited hedging activities, but only to the extent of buying protection price floors for portions of its and the Company-managed limited partnerships' oil and gas production. Costs and/or benefits derived from these price floors are accordingly recorded as a reduction or increase, as applicable, in oil and gas sales revenue and have not been significant for any year presented. The costs to purchase put options are amortized over the option period.

During 1998, the Company entered into oil and natural gas price hedging contracts covering a portion of the Company's and its affiliated partnerships' oil and natural gas production. For January, 1,500,000 MMBtu of the natural gas production was covered, and February was covered for 3,000,000 MMBtu of natural gas, each at a minimum price of \$2.00 per MMBtu. March was covered for 2,000,000 MMBtu of natural gas at a minimum price of \$1.80 per MMBtu and 500,000 MMBtu at \$1.90 per MMBtu. For the months of April, May, June, and July, 1,000,000 MMBtu were covered, providing for a minimum price of \$1.80, \$1.90, \$2.10, and \$2.10 per MMBtu, respectively.

For the months of January and February 1998, 60,000 Bbls of oil production were covered each month, providing for a minimum price of \$18.00 per Bbl. Costs related to 1998 hedging activities totaled approximately \$377,000, with benefits of approximately \$101,000 being received, resulting in a net cash outlay of approximately \$276,000 or \$0.007 per Mcfe.

The Company had entered into four put option contracts for 1999 production by December 31, 1998, three of which remained open at year-end. January was covered for 2,000,000 MMBtu of natural gas at \$2.00 per MMBtu, with a net profit of approximately \$154,000. The three open contracts at December 31, 1998, covered 1,000,000 MMBtu and 1,800,000 MMBtu of natural gas production for February at minimum prices of \$1.80 and \$1.70 per MMBtu, respectively, and 2,800,000 MMBtu of natural gas for March at a minimum price of \$1.60 per MMBtu. The costs related

to these 1999 contracts totaled \$317,016 and had a fair market value of \$486,680 as of December 31, 1998.

### Acquisition Activities

Since 1979, the Company has acquired approximately \$537.5 million of producing oil and gas properties on behalf of itself and its co-investors in 133 separate transactions. In recent years, the Company's acquisition activities have declined, as it has fulfilled its obligation to buy producing properties for the remaining partnerships which invested in such properties and as industry conditions brought a redirection of the Company's strategy towards increasing reserves through drilling. As of December 31, 1997, all such partnerships investing in producing properties had spent their available capital resources on producing properties. Therefore, the Company anticipates all future acquisition activity will be on its own behalf. The Company has acquired for its own account approximately \$181.0 million of producing properties, with original proved reserves estimated at 279.9 Bcfe. The Company's producing property acquisition expenditures in the past three years were approximately \$1.5 million in 1996, \$8.4 million in 1997, and \$59.5 million in 1998. The Company's acquisition costs have averaged \$0.52 per Mcfe over this three-year period.

The Company uses a disciplined, market-driven approach to acquisitions, generally seeking to acquire properties in close proximity to its current reserves with the potential to add reserves and production through additional development and exploration efforts.

### Foreign Activities

*New Zealand.* Since October 1995, the Company has been issued two Petroleum Exploration Permits by the New Zealand Minister of Energy. The first permit covered approximately 65,000 acres in the Onshore Taranaki Basin of New Zealand's North Island, and the second covered approximately 69,300 adjacent acres. A wholly-owned subsidiary, Swift Energy New Zealand Limited, formed in late 1997, conducts its New Zealand activities and owns the interest in the permits. In March 1998, the Company surrendered approximately 46,400 acres covered in the first permit, and the remaining acreage has been included as an extension of the area covered in the second permit. Under the terms of the expanded permit, the Company is obligated to drill one exploratory well prior to August 12, 1999. All other obligations under the permit have been fulfilled, including the reinterpretation of existing seismic data and the acquisition and processing of new seismic data.

On October 23, 1998, the Company entered into separate agreements with Marabella Enterprises Ltd.

(Marabella), a subsidiary of Bligh Oil & Minerals N.L., an Australian company, to obtain from Marabella a 25% working interest in another New Zealand Petroleum Exploration Permit and for Marabella to become a 5% participant in the Company's permit. An exploration well on the Marabella permit commenced drilling on October 16, 1998, the results of which were unsuccessful. Accordingly, the \$400,000 cost of such well was charged against earnings. The Company has also agreed in principle to participate with Marabella in an additional permit as a 17.5% working interest owner.

At December 31, 1998, the Company's investment in New Zealand was approximately \$5.4 million and is included in the unproved properties portion of oil and gas properties. Approximately \$0.4 million of such costs have been impaired.

*Russia.* On September 3, 1993, the Company signed a Participation Agreement with Senega, a Russian Federation joint stock company (in which the Company has an indirect interest of less than 1%), to assist in the development and production of reserves from two fields in Western Siberia, providing the Company with a minimum 5% net profits interest from the sale of hydrocarbon products from the fields for providing managerial, technical, and financial support to Senega. Additionally, the Company purchased a 1% net profits interest from Senega for \$0.3 million.

On December 10, 1997, the Company amended and restated the Participation Agreement. Under the amended and restated Participation Agreement, the Company retains its 6% net profits interest in the Samburg Field and agreed to assist Senega in obtaining investments necessary to develop the field. Senega is charged with the management and control of the field development. The Company's investment in Russia, prior to its impairment in the third quarter of 1998, was approximately \$10.8 million and was previously included in the unproved properties portion of oil and gas properties. However, the economic and political uncertainty and currency concerns that arose during the third quarter of 1998 in Russia, combined with the price volatility and severe tightening of international capital markets, caused the Company to re-evaluate the timing of the recovery of its capitalized costs in that country. See Note 1 to the Company's financial statements for a more detailed discussion of the impairment. Subsequent to such impairment, any costs incurred in Russia have been reported as a charge to earnings.

*Venezuela.* The Company formed a wholly-owned subsidiary, Swift Energy de Venezuela, C. A., for the purpose of submitting a bid on August 5, 1993, under the Venezuelan Marginal Oil Field Reactivation Program. Although the Company did not win the bid, it has continued to gather information relating to reserves and geological and geophysical data in Venezuela and continued to pursue cooperative ventures involving other fields and opportunities in Venezuela. The Company evaluated a number of blocks being offered by Petroleos de Venezuela, S. A., under the Third Operating Agreement Round in 1997 but decided against submitting any bid on these blocks. The Company has entered into an agreement with Tecnoconsult, S. A., and Corporation EDC, S.A.C.A., Venezuelan companies, to jointly formulate and submit a proposal to Petroleos de Venezuela, S. A., for the construction and operation of a methane pipeline. Currently, the technical and economic feasibility of

the project is under study. The Company's investment in Venezuela, prior to its impairment in the third quarter of 1998, was approximately \$2.8 million and was previously included in the unproved properties portion of oil and gas properties. However, the economic uncertainty and currency concerns in Venezuela, combined with the price volatility and severe tightening of international capital markets, caused the Company to re-evaluate its prospects of participating in further Venezuelan exploration activities in the near-term and the recovery of its capitalized costs in that country. See Note 1 to the Company's financial statements for a more detailed discussion of the impairment. Subsequent to such impairment, any costs incurred in Venezuela have been reported as a charge to earnings.

## **Oil and Gas Reserves**

The following table presents information regarding proved reserves of oil and gas attributable to the Company's interests in producing properties as of December 31, 1998, 1997, and 1996. The information set forth in the table is based on proved reserves reports prepared by the Company and audited by H. J. Gruy and Associates, Inc., Houston, Texas, independent petroleum engineers. Gruy's estimates were based upon review of production histories and other geological, economic, ownership, and engineering data provided by the Company. In accordance with Securities and Exchange Commission guidelines, the Company's estimates of future net revenues from the Company's proved reserves and the PV-10 Value are made using oil and gas sales prices in effect as of the dates of such estimates and are held constant throughout the life of the properties, except where such guidelines permit alternate treatment, including, in the case of gas contracts, the use of fixed and determinable contractual price escalations. Proved reserves as of December 31, 1998, were estimated based upon weighted average prices of \$2.23 per Mcf of natural gas and \$11.23 per barrel of oil, compared to \$2.78 and \$15.76 in 1997 and \$4.47 and \$23.75 in 1996, respectively. The Company has interests in certain tracts that are estimated to have additional hydrocarbon reserves that cannot be classified as proved and are not reflected in the following table. The proved reserves presented for all periods also exclude any reserves attributable to the volumetric production payment.

The table sets forth estimates of future net revenues presented on the basis of unescalated prices and costs in accordance with criteria prescribed by the Securities and Exchange Commission and their PV-10 Value. Operating costs, development costs, and certain production-related taxes were deducted in arriving at the estimated future net revenues. No provision was made for income taxes. The estimates of future net revenues and their present value differ in this respect from the standardized measure of discounted future net cash flows set forth in Supplemental Information to the Company's financial statements, which is calculated after provision for future income taxes. In cases where producing properties are subject to gas purchase contracts and the amount of gas purchased thereunder was reduced during 1998, gas projections used to estimate future net revenues were based on the reduced gas purchases for the affected producing properties. The assumption was made that purchases in 1999 and thereafter will be made at an unrestricted level.

|  | Year Ended December 31, |                       |                       |
|--|-------------------------|-----------------------|-----------------------|
|  | 1998                    | 1997                  | 1996                  |
| <b>Estimated Proved Oil and Gas Reserves</b>   |                         |                       |                       |
| Net natural gas reserves (Mcf):  |                         |                       |                       |
| Proved developed   | 197,105,963             | 191,108,214           | 135,424,880           |
| Proved undeveloped   | 155,294,872             | 123,197,455           | 90,333,321            |
| Total  | <u>352,400,835</u>      | <u>314,305,669</u>    | <u>225,758,201</u>    |
| Net oil reserves (Bbl):  |                         |                       |                       |
| Proved developed   | 7,142,566               | 4,288,696             | 3,622,480             |
| Proved undeveloped   | 6,815,359               | 3,570,222             | 1,861,829             |
| Total  | <u>13,957,925</u>       | <u>7,858,918</u>      | <u>5,484,309</u>      |
| <b>Estimated Present Value of Proved Reserves</b>  |                         |                       |                       |
| Estimated present value of future net cash flows from proved reserves discounted at 10% per annum: |                         |                       |                       |
| Proved developed   | \$ 243,124,194          | \$ 244,365,044        | \$ 310,408,949        |
| Proved undeveloped   | 97,660,811              | 105,979,738           | 160,776,008           |
| Total  | <u>\$ 340,785,005</u>   | <u>\$ 350,344,782</u> | <u>\$ 471,184,957</u> |

The Company's total proved developed and undeveloped reserves increased 21% at December 31, 1998, over amounts at December 31, 1997, as shown above and in Supplemental Information to the Company's financial statements. At year-end 1998, 45% of the reserves were proved undeveloped reserves. This reflects the increased emphasis on development and exploration activities. In 1997, 40% of proved reserves were undeveloped and 60% were proved developed.

Changes in quantity estimates and the estimated present value of proved reserves are affected by the change in crude oil and natural gas prices at the end of each year. While the Company's total proved reserves quantities (on an equivalent Bcfe basis) at year-end 1998 increased by 21% over reserves quantities a year earlier, the PV-10 Value of those reserves decreased 3% from the PV-10 Value at year-end 1997. This decrease was due almost entirely to pricing declines at year-end 1998 as compared to year-end 1997, which more than offset the 21% Bcfe increase in reserves quantities. Product prices for natural gas declined 20% during 1998 from \$2.78 per Mcf at December 31, 1997, to \$2.23 per Mcf at year-end 1998, matched by a 29% decrease in the price of oil between the two dates, from \$15.76 to \$11.23 per barrel.

Proved reserves are estimates of hydrocarbons to be recovered in the future. Reservoir engineering is a subjective process of estimating the sizes of underground accumulations of oil and gas that cannot be measured in an exact way. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Reserves reports of other engineers might differ from the reports contained herein. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimate. Future prices received for the sale of oil and gas may be different from those used in preparing these reports. The amounts and timing of future operating and development costs may also differ from those used. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered. There can be no assurance that these estimates are accurate predictions of the present value of future net cash flows from oil and gas reserves.

A portion of the Company's proved reserves has been accumulated through the Company's interests in the limited partnerships for which it serves as general partner. The estimates of future net cash flows and their present values, based on period end prices, assume that some of the limited partnerships in which the Company owns interests will achieve payout status in the future. At December 31, 1998, 17 of the limited partnerships managed by the Company had achieved payout status.

No other reports on the Company's reserves have been filed with any federal agency.

#### Oil and Gas Wells

The following table sets forth the gross and net wells in which the Company owned an interest at the following dates:

|                   | Oil Wells | Gas Wells | Total Wells <sup>1</sup> |
|-------------------|-----------|-----------|--------------------------|
| December 31, 1998 |           |           |                          |
| Gross             | 657       | 1,060     | 1,717                    |
| Net               | 89.4      | 494.5     | 583.9                    |
| December 31, 1997 |           |           |                          |
| Gross             | 625       | 926       | 1,551                    |
| Net               | 48.1      | 381.7     | 429.8                    |
| December 31, 1996 |           |           |                          |
| Gross             | 734       | 1,068     | 1,802                    |
| Net               | 59.5      | 222.9     | 282.4                    |

<sup>1</sup>Excludes 36 service wells in 1998, 16 service wells in 1997, and 26 service wells in 1996.

#### Oil and Gas Acreage

As is customary in the industry, the Company generally acquires oil and gas acreage without any warranty of title except as to claims made by, through, or under the transferor. Although the Company has title to developed acreage examined prior to acquisition in those cases in which the economic significance of the acreage justifies the cost, there can be no assurance that losses will not result from title defects or from defects in the assignment of leasehold rights. In many instances, title opinions may not be obtained if in the Company's judgment it would be uneconomical or impractical to do so.

The following table sets forth the developed and undeveloped domestic leasehold acreage held by the Company at December 31, 1998:

|                  | Developed <sup>1</sup> |            | Undeveloped <sup>1</sup> |            |
|------------------|------------------------|------------|--------------------------|------------|
|                  | Gross                  | Net        | Gross                    | Net        |
| Alabama          | 4,495.38               | 616.70     | 292.00                   | 72.90      |
| Arkansas         | 3,339.49               | 1,736.30   | 8,092.80                 | 5,022.95   |
| Kansas           | —                      | —          | 4,600.00                 | 1,988.80   |
| Louisiana        | 100,233.66             | 50,356.48  | 159,555.53               | 101,109.80 |
| Mississippi      | 4,186.10               | 2,240.85   | 3,693.84                 | 910.69     |
| Montana          | —                      | —          | 4,411.28                 | 4,411.28   |
| Oklahoma         | 33,240.59              | 14,197.02  | 3,209.04                 | 886.50     |
| Texas            | 260,232.49             | 146,577.24 | 301,336.20               | 161,354.21 |
| Wyoming          | 4,713.90               | 1,969.49   | 120,253.29               | 104,579.29 |
| All other states | —                      | —          | 6,317.48                 | 1,286.06   |
| Total            | 410,441.61             | 217,694.08 | 611,761.46               | 381,622.48 |

<sup>1</sup>Fee minerals acquired in the Toledo Bend Properties acquisition are not included in the above leasehold acreage table. The Company acquired 23,178.56 developed fee mineral acres and 114,034.44 undeveloped fee mineral acres for a total of 137,213 fee mineral acres.

## Partnerships

For many years, the Company relied on limited partnerships as its principal vehicle to fund its activities. The Company has formed 109 limited partnerships which had raised a total of approximately \$509.5 million at December 31, 1998. However, as the Company has increasingly shifted its emphasis to development and exploration activities and its reserves base has grown, the Company has significantly reduced its reliance on limited partnership financing.

During 1996, the limited partners in 18 partnerships, which had been in operation over nine years and had produced a substantial majority of their reserves, voted to sell their remaining properties and liquidate the limited partnerships. Of these partnerships, 10 were the earliest public income partnerships formed in 1984 to 1986. In early 1997, eight private drilling partnerships formed in 1979 to 1985 were liquidated. During 1997, the limited partners in an additional 11 partnerships, formed in 1990 and 1991, voted to sell their properties and liquidate the limited partnerships, which liquidation occurred in June 1998.

From 1984 to 1995, the Company formed limited partnerships and joint ventures for the purpose of acquiring interests in producing oil and gas properties. Since 1993, the Company also has offered private partnerships formed to engage in the drilling for oil and gas reserves. The Company serves as the managing general partner of these entities. As of December 31, 1998, thirteen private drilling partnerships had been formed (one formed in each of 1993 and 1994, three in each of 1995, 1996, and 1997, and two in 1998) with aggregate investor contributions of approximately \$66.1 million.

The private drilling partnerships have been offered on a no-load basis under which the Company pays all selling and offering expenses of the offering. Amounts paid by the Company are treated as a capital contribution to each partnership. The Company also is entitled to a general and administrative overhead allowance and an incentive amount. In certain partnerships, the Company does not bear any of the costs incurred in acquiring or drilling properties. The Company pays approximately 20% of all continuing costs (approximately 30% after payout and 35% after 200% payout),

and the Company is entitled to receive 20% of net revenues distributed by each such partnership prior to payout, 30% distributed after payout, and 35% distributed after 200% payout. As managing general partner of certain other partnerships, the Company pays out of its own corporate funds the capital costs, consisting of all prospect costs and the non-deductible, tangible portion of drilling and completion costs. The Company pays approximately 40% of all continuing costs (approximately 45% after payout and 50% after 200% payout), and the Company is entitled to receive 40% of net revenues distributed by each such partnership prior to payout, 45% distributed after payout, and 50% distributed after 200% payout.

In October 1998, the Company notified investors in 63 Swift-managed production partnerships formed between 1986 and 1994 that it had delayed calling investor meetings to consider its purchase of all of the oil and gas properties owned by these partnerships, which was proposed in March 1998. This decision principally reflected significant market changes that had occurred during the long period necessary for regulatory review of soliciting materials, the age of the third-party appraisals of these partnership properties, and the much publicized weakness in both the equity and debt markets for energy companies. During the last six months, the weakness in oil and natural gas prices has deepened, creating concern over the appropriateness of selling properties at this time. The Company expects to continue to re-evaluate the status and operation of these partnerships, whether to propose some form of liquidating transaction, and if so when and in what form.

## Risk Management

The Company's operations are subject to all of the risks normally incident to the exploration for and the production of oil and gas, including blowouts, cratering, pipe failure, casing collapse, oil spills, and fires, each of which could result in severe damage to or destruction of oil and gas wells, production facilities or other property, or individual injuries. The oil and gas exploration business is also subject to environmental hazards, such as oil spills, gas leaks, and ruptures and discharges of toxic substances or gases that could expose the Company to substantial liability due to pollution and other environmental damage. Additionally, as managing general partner of limited partnerships, the Company is solely responsible for the day-to-day conduct of the limited partnerships' affairs and accordingly has liability for expenses and liabilities of the limited partnerships. The Company maintains comprehensive insurance coverage, including general liability insurance in an amount not less than \$35.0 million, as well as general partner liability insurance. The Company believes that its insurance is adequate and customary for companies of a similar size engaged in comparable operations, but losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage.

## Competition

The oil and gas industry is highly competitive in all its phases. The Company encounters strong competition from many other oil and gas producers, including many that possess substantial financial resources, in acquiring economically desirable producing properties and exploratory drilling prospects, and in obtaining equipment and labor to operate and maintain its properties. Continued decreases in natural gas and oil prices have had an effect on the Company's cash flow, capital expenditures, and drilling schedule. In light of the extreme volatility of prices, it is

impossible to predict the length of time that prices may remain at such levels or may move to higher or lower levels.

## **Regulations**

### **Environmental Regulations**

The federal government and various state and local governments have adopted laws and regulations regarding the protection of human health and the environment. These laws and regulations may require the acquisition of a permit by operators before drilling commences, prohibit drilling activities on certain lands lying within wilderness areas, wetlands, or where pollution might cause serious harm, and impose substantial liabilities for pollution resulting from drilling operations, particularly with respect to operations in onshore and offshore waters or on submerged lands. These laws and regulations may increase the costs of drilling and operating wells. Because these laws and regulations change frequently, the costs to the Company of compliance with existing and future environmental regulations cannot be predicted with certainty.

### **Federal Regulation of Natural Gas**

The transportation and certain sales of natural gas in interstate commerce are heavily regulated by agencies of the federal government. The following discussion is intended only as a brief summary of agency rules and regulations that may affect the production and sale of the Company's natural gas. This summary should not be relied upon as a complete review of applicable natural gas regulatory provisions.

In April 1992, the Federal Energy Regulatory Commission ("FERC") issued Order No. 636 pertaining to pipeline restructuring. This rule requires interstate pipelines to unbundle transportation and sales services by separately stating the price of each service and by providing customers only the particular service desired, without regard to the source for purchase of the gas. The rule also requires pipelines to (i) provide nondiscriminatory "no-notice" service allowing firm commitment shippers to receive delivery of gas on demand up to certain limits without penalties, (ii) establish a basis for release and reallocation of firm upstream pipeline capacity and (iii) provide non-discriminatory access to capacity by firm transportation shippers on a downstream pipeline. The rule requires interstate pipelines to use a straight fixed variable rate design.

In addition, interstate pipelines that transport gas for others must provide transportation service to producers,

distributors and all other shippers of natural gas on a nondiscriminatory, "first-come, first-served" basis ("open access transportation"), so that producers and other shippers can sell natural gas directly to end-users.

Gas produced normally will be sold to intermediaries who have entered into transportation arrangements with pipeline companies. These intermediaries typically accumulate gas purchased from a number of producers and sell the gas to end-users through open access transportation.

### **State Regulations**

Production of any oil and gas by the Company will be affected to some degree by state regulations. Many states in which the Company operates have statutory provisions regulating the production and sale of oil and gas, including provisions regarding deliverability. Such statutes, and the regulations promulgated in connection therewith, are generally intended to prevent waste of oil and gas and to protect correlative rights to produce oil and gas between owners of a common reservoir. Certain state regulatory authorities also regulate the amount of oil and gas produced by assigning allowable rates of production to each well or proration unit.

### **Federal Leases**

Some of the Company's properties are located on federal oil and gas leases administered by various federal agencies, including the Bureau of Land Management. Various regulations and orders affect the terms of leases, exploration and development plans, methods of operation, and related matters.

### **Employees**

At December 31, 1998, the Company employed 203 persons. None of the Company's employees are represented by a union. Relations with employees are considered to be good.

### **Facilities**

The Company and SEMCO occupy approximately 75,000 square feet of office space at 16825 Northchase Drive, Houston, Texas, under a ten year lease expiring in 2005. The lease requires payments of approximately \$95,000 per month. The Company has field offices in various locations from which Company employees supervise local oil and gas operations.

## Glossary of Abbreviations and Terms

The following abbreviations and terms have the indicated meanings when used in this report:

**Bbl** — Barrel or barrels of oil.

**Bcf** — Billion cubic feet of natural gas.

**Bcfe** — Billion cubic feet of natural gas equivalent (see Mcfe).

**Development Well** — A well drilled within the presently proved productive area of an oil or natural gas reservoir, as indicated by reasonable interpretation of available data, with the objective of completing in that reservoir.

**Discovery Cost** — With respect to proved reserves, a three-year average (unless otherwise indicated) calculated by dividing total incurred exploration and development costs (exclusive of future development costs) by net reserves added during the period through extensions, discoveries, and other additions.

**Dry Well** — An exploratory or development well that is not a producing well.

**Exploratory Well** — A well drilled either in search of a new, as yet undiscovered oil or natural gas reservoir or to greatly extend the known limits of a previously discovered reservoir.

**Gross Acre** — An acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

**Gross Well** — A well in which a working interest is owned. The number of gross wells is the total number of wells in which a working interest is owned.

**MBbl** — Thousand barrels of oil.

**Mcf** — Thousand cubic feet of natural gas.

**Mcfe** — Thousand cubic feet of natural gas equivalent, which is determined using the ratio of one barrel of oil, condensate, or natural gas liquids to 6 Mcf of natural gas.

**MMBbl** — Million barrels of oil.

**MMBtu** — Million British thermal units, which is a heating equivalent measure for natural gas and is an alternate measure of natural gas reserves, as opposed to Mcf, which is strictly a measure of natural gas volumes. Typically, prices quoted for natural gas are designated as price per MMBtu, the same basis on which natural gas is contracted for sale.

**MMcf** — Million cubic feet of natural gas.

**MMcfe** — Million cubic feet of natural gas equivalent (see Mcfe).

**Net Acre** — A net acre is deemed to exist when the sum of fractional ownership working interests in gross acres equals one. The number of net acres is the sum of fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

**Net Well** — A net well is deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of fractional working interests owned in gross wells expressed as whole numbers and fractions thereof.

**Producing Well** — An exploratory or development well found to be capable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

**Proved Developed Oil and Gas Reserves** — Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

**Proved Oil and Gas Reserves** — The estimated quantities of crude oil, natural gas, and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made.

**Proved Undeveloped Oil and Gas Reserves** — Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

**PV-10 Value** — The estimated future net revenue to be generated from the production of proved reserves discounted to present value using an annual discount rate of 10%. These amounts are calculated net of estimated production costs and future development costs, using prices and costs in effect as of a certain date, without escalation and without giving effect to non-property related expenses, such as general and administrative expenses, debt service, future income tax expense, or depreciation, depletion, and amortization.

**Reserves Replacement Cost** — With respect to proved reserves, a three-year average (unless otherwise indicated) calculated by dividing total incurred acquisition, exploration, and development costs (exclusive of future development costs) by net reserves added during the period.

**Volumetric Production Payment** — The 1992 agreement pursuant to which the Company financed the purchase of certain oil and natural gas interests and committed to deliver certain monthly quantities of natural gas.

### Item 3. Legal Proceedings

From time to time, litigation arises in the ordinary course of Swift's oil and gas drilling and production activities. In early 1997, Swift and the Lower Colorado River Authority, the "LCRA," filed claims against each other in the 155th Judicial District Court of Fayette County, Texas, over the interpretation of an oil and gas farmout agreement from LCRA to Swift covering land in Fayette County, Texas. Swift originally sued to force LCRA to assign to Swift leases which LCRA had refused to assign, covering wells successfully drilled by Swift on the farmout acreage, and seeking declaration as to the parties' interests in the properties involved. LCRA counterclaimed for damages and claimed fraud and conversion, plus conspiracy to convert oil and gas among Swift, certain of its officers and managed partnerships. LCRA has not quantified its damages, but in December 1998 alleged that they do not exceed \$10 million, exclusive of punitive damages. Swift does not believe LCRA's counterclaims are valid nor that the claimed damage amount is a credible number, and Swift intends to vigorously pursue its claims under the farmout. A July 6, 1999, trial date has been tentatively set for this case. Although certain proceeds from production of the field involved have been escrowed in the court pending resolution of this case, based on discovery to date, the Company does not believe that this case will have a materially adverse impact upon its financial condition or results of operations.

### Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted during the fourth quarter of 1998 to a vote of security holders.

## PART II

### Item 5. Market for the Registrant's Common Equity and Related Stockholder Matters

#### COMMON STOCK, 1997 AND 1998

Swift Energy Company common stock is traded on the New York Stock Exchange and the Pacific Exchange, Inc., under the symbol "SFY." The high and low quarterly sales prices for the common stock for 1997 and 1998 are as follows:

|      | 1997             |                   |                  |                   | 1998             |                   |                  |                   |
|------|------------------|-------------------|------------------|-------------------|------------------|-------------------|------------------|-------------------|
|      | First<br>Quarter | Second<br>Quarter | Third<br>Quarter | Fourth<br>Quarter | First<br>Quarter | Second<br>Quarter | Third<br>Quarter | Fourth<br>Quarter |
| Low  | \$19.32          | \$16.93           | \$18.86          | \$19.25           | \$15.88          | \$15.00           | \$8.81           | \$6.94            |
| High | \$34.20          | \$26.02           | \$26.48          | \$31.00           | \$21.00          | \$20.75           | \$16.75          | \$11.19           |

Since inception, no cash dividends have been declared on the Company's common stock. Cash dividends are restricted under the terms of the Company's credit agreement, as discussed in Note 4 to the Company's financial statements, and the Company presently intends to continue a policy of using retained earnings for expansion of its business. The stock prices for the first three quarters of 1997 have been revised to reflect a 10% stock dividend declared in October 1997.

Swift Energy had approximately 565 stockholders of record as of December 31, 1998.

## Item 6. Selected Financial Data

|  | 1998                  | 1997                 | 1996                 | 1995                 |
|--|-----------------------|----------------------|----------------------|----------------------|
| <b>Revenues</b>  |                       |                      |                      |                      |
| Oil and Gas Sales  | \$80,067,837          | \$69,015,189         | \$52,770,672         | \$22,527,892         |
| Fees and Earned Interests <sup>2</sup>   | \$333,940             | \$745,856            | \$937,238            | \$590,441            |
| Interest Income  | \$107,374             | \$2,395,406          | \$433,352            | \$212,329            |
| Other, Net   | \$1,960,070           | \$2,555,729          | \$2,156,764          | \$1,761,568          |
| <b>Total Revenues</b>  | <b>\$82,469,221</b>   | <b>\$74,712,180</b>  | <b>\$56,298,026</b>  | <b>\$25,092,230</b>  |
| <b>Operating Income (Loss)</b>   | <b>\$(73,391,581)</b> | <b>\$33,129,606</b>  | <b>\$28,785,783</b>  | <b>\$6,894,537</b>   |
| <b>Net Income (Loss)</b>   | <b>\$(48,225,204)</b> | <b>\$22,310,189</b>  | <b>\$19,025,450</b>  | <b>\$4,912,512</b>   |
| <b>Net Cash Provided by Operating Activities</b>   | <b>\$54,249,017</b>   | <b>\$55,255,965</b>  | <b>\$37,102,578</b>  | <b>\$14,376,463</b>  |
| <b>Per Share Data</b>  |                       |                      |                      |                      |
| Weighted Average Shares Outstanding <sup>3</sup>   | 16,436,972            | 16,492,856           | 15,000,901           | 10,035,143           |
| Earnings (Loss) per Share—Basic <sup>3</sup>   | \$(2.93)              | \$1.35               | \$1.27               | \$0.49               |
| Earnings (Loss) per Share—Diluted <sup>3</sup>   | \$(2.93)              | \$1.26               | \$1.25               | \$0.49               |
| Shares Outstanding at Year-End   | 16,291,242            | 16,459,156           | 15,176,417           | 12,509,700           |
| Book Value per Share   | \$6.71                | \$9.69               | \$9.41               | \$7.46               |
| Market Price <sup>3</sup>  |                       |                      |                      |                      |
| High   | \$21.00               | \$34.20              | \$28.86              | \$11.48              |
| Low  | \$6.94                | \$16.93              | \$9.89               | \$7.05               |
| Year-End Close   | \$7.38                | \$21.06              | \$27.16              | \$10.91              |
| <i>Pro forma amounts assuming 1994 change in accounting principle is applied retroactively<sup>2</sup></i> |                       |                      |                      |                      |
| Net Income (Loss)  | \$(48,225,204)        | \$22,310,189         | \$19,025,450         | \$4,912,512          |
| Earnings (Loss) per Share—Basic <sup>3</sup>   | \$(2.93)              | \$1.35               | \$1.27               | \$0.49               |
| Earnings (Loss) per Share—Diluted <sup>3</sup>   | \$(2.93)              | \$1.26               | \$1.25               | \$0.49               |
| <b>Assets</b>  |                       |                      |                      |                      |
| Current Assets   | \$35,246,431          | \$29,981,786         | \$101,619,478        | \$43,380,454         |
| Oil and Gas Properties, Net of Accumulated Depreciation, Depletion, and Amortization                       | \$356,457,106         | \$301,312,847        | \$200,010,375        | \$125,217,872        |
| <b>Total Assets</b>  | <b>\$403,645,267</b>  | <b>\$339,115,390</b> | <b>\$310,375,264</b> | <b>\$175,252,707</b> |
| <b>Liabilities</b>   |                       |                      |                      |                      |
| Current Liabilities  | \$31,415,054          | \$28,517,664         | \$32,915,616         | \$40,133,269         |
| Convertible Notes and Bank Borrowings  | \$261,200,000         | \$122,915,000        | \$115,000,000        | \$28,750,000         |
| <b>Total Liabilities</b>   | <b>\$294,282,628</b>  | <b>\$179,714,470</b> | <b>\$167,613,654</b> | <b>\$81,906,742</b>  |
| <b>Stockholders' Equity</b>  | <b>\$109,362,639</b>  | <b>\$159,400,920</b> | <b>\$142,761,610</b> | <b>\$93,345,965</b>  |
| <b>Number of Employees</b>   | <b>203</b>            | <b>194</b>           | <b>191</b>           | <b>176</b>           |
| <b>Producing Wells</b>   |                       |                      |                      |                      |
| Swift Operated   | 836                   | 650                  | 842                  | 767                  |
| Outside Operated   | 917                   | 917                  | 986                  | 3,316                |
| <b>Total Producing Wells</b>   | <b>1,753</b>          | <b>1,567</b>         | <b>1,828</b>         | <b>4,083</b>         |
| <b>Wells Drilled (Gross)</b>   | <b>75</b>             | <b>182</b>           | <b>153</b>           | <b>76</b>            |
| <b>Proved Reserves</b>   |                       |                      |                      |                      |
| Natural Gas (Mcf)  | 352,400,835           | 314,305,669          | 225,758,201          | 143,567,520          |
| Oil & Condensate (barrels)   | 13,957,925            | 7,858,918            | 5,484,309            | 5,421,981            |
| <b>Total Proved Reserves (Mcf equivalent)</b>  | <b>436,148,385</b>    | <b>361,459,177</b>   | <b>258,664,055</b>   | <b>176,099,406</b>   |
| <b>Production (Mcf equivalent)<sup>4</sup></b>   | <b>39,030,030</b>     | <b>25,393,744</b>    | <b>19,437,114</b>    | <b>11,186,573</b>    |
| <b>Average Sales Price</b>   |                       |                      |                      |                      |
| Natural Gas (per Mcf)  | \$2.08                | \$2.68               | \$2.57               | \$1.77               |
| Oil (per barrel)   | \$11.86               | \$17.59              | \$19.82              | \$15.66              |

<sup>1</sup>Additional 1994 Data: Income Before Cumulative Effect of Change in Accounting Principle—\$3,725,671; Cumulative Effect of Change in Accounting Principle—\$(16,772,698); Per Share Amounts—Basic—Income Before Cumulative Effect of Change in Accounting Principle—\$0.51, Cumulative Effect of Change in Accounting Principle—\$(2.29); Per Share Amounts—Diluted—Income Before Cumulative Effect of Change in Accounting Principle—\$0.51, Cumulative Effect of Change in Accounting Principle—\$(2.29).

<sup>2</sup>As of January 1, 1994, the Company changed its revenue recognition policy for earned interests. Accordingly, in 1994 to 1998, "Fees and Earned Interests" does not include earned interests revenues.

<sup>3</sup>Amounts have been retroactively restated in all periods presented to give recognition to: (a) an equivalent change in capital structure as a result of two 10% stock dividends, one in September 1994, the other in October 1997 (see Note 2 to the Company's financial statements); and (b) the adoption of Statement of Financial Accounting Standards No. 128, "Earnings per Share" (see Note 2 to the Company's financial statements).

<sup>4</sup>Natural gas production for 1992, 1993, 1994, 1995, 1996, 1997, and 1998 includes 1,148,862, 1,581,206, 1,358,375, 1,211,255, 1,156,361, 1,015,226, and 866,232 Mcf, respectively, delivered under the Company's volumetric production payment agreement (see Note 1 to the Company's financial statements).

| 1994 <sup>1</sup> | 1993          | 1992          | 1991          | 1990          | 1989         | 1988         |
|-------------------|---------------|---------------|---------------|---------------|--------------|--------------|
| \$19,802,188      | \$15,535,671  | \$12,420,222  | \$8,361,771   | \$7,328,190   | \$3,984,835  | \$2,838,433  |
| \$701,528         | \$4,071,970   | \$2,716,277   | \$2,231,729   | \$9,882,953   | \$8,802,816  | \$8,073,530  |
| \$47,980          | \$201,584     | \$113,387     | \$192,694     | \$705,786     | \$260,286    | \$165,909    |
| \$1,072,535       | \$604,599     | \$515,931     | \$541,502     | \$323,981     | \$232,261    | \$488,131    |
| \$21,624,231      | \$20,413,824  | \$15,765,817  | \$11,327,696  | \$18,240,910  | \$13,280,198 | \$11,566,003 |
| \$4,837,829       | \$6,628,608   | \$4,687,519   | \$3,748,741   | \$10,811,044  | \$8,716,673  | \$7,040,165  |
| \$(13,047,027)    | \$4,896,253   | \$4,084,760   | \$2,512,815   | \$7,170,642   | \$5,709,098  | \$4,678,317  |
| \$10,394,514      | \$7,238,340   | \$6,349,080   | \$5,911,588   | \$4,813,435   | \$2,751,381  | \$393,564    |
| 7,308,673         | 7,246,884     | 6,748,548     | 5,899,629     | 5,806,436     | 5,129,654    | 4,897,379    |
| \$(1.79)          | \$0.68        | \$0.61        | \$0.43        | \$1.23        | \$1.11       | \$0.96       |
| \$(1.79)          | \$0.64        | \$0.61        | \$0.43        | \$1.23        | \$1.11       | \$0.96       |
| 6,685,137         | 6,001,075     | 5,968,579     | 4,955,134     | 4,848,315     | 4,764,862    | 4,068,968    |
| \$6.30            | \$9.08        | \$8.26        | \$7.80        | \$7.36        | \$5.84       | \$3.88       |
| \$10.35           | \$11.57       | \$7.85        | \$9.09        | \$10.65       | \$11.15      | \$8.68       |
| \$7.75            | \$7.14        | \$4.65        | \$4.34        | \$6.93        | \$5.78       | \$5.58       |
| \$8.86            | \$7.85        | \$7.55        | \$4.95        | \$8.57        | \$9.50       | \$5.68       |
| \$3,725,671       | \$4,322,478   | \$3,729,851   | \$2,950,245   | \$3,107,451   | \$2,185,276  | \$898,962    |
| \$0.51            | \$0.60        | \$0.55        | \$0.50        | \$0.54        | \$0.43       | \$0.18       |
| \$0.51            | \$0.57        | \$0.55        | \$0.50        | \$0.54        | \$0.43       | \$0.18       |
| \$39,208,418      | \$65,307,120  | \$30,830,173  | \$47,859,278  | \$72,537,521  | \$54,818,404 | \$9,304,370  |
| \$88,415,612      | \$89,656,577  | \$64,301,509  | \$47,655,917  | \$41,952,212  | \$27,935,170 | \$19,973,454 |
| \$135,672,743     | \$160,892,917 | \$100,243,469 | \$101,421,573 | \$118,227,480 | \$85,007,293 | \$31,463,220 |
| \$52,345,859      | \$55,565,437  | \$27,876,687  | \$50,851,447  | \$71,514,938  | \$49,354,128 | \$9,756,431  |
| \$28,750,000      | \$28,750,000  | \$0           | \$0           | \$0           | \$0          | \$0          |
| \$93,545,612      | \$106,427,203 | \$50,962,183  | \$62,761,217  | \$82,559,406  | \$57,198,476 | \$15,694,272 |
| \$42,127,131      | \$54,465,714  | \$49,281,286  | \$38,660,356  | \$35,668,074  | \$27,808,817 | \$15,768,948 |
| 209               | 188           | 178           | 171           | 164           | 131          | 116          |
| 750               | 795           | 688           | 674           | 691           | 579          | 491          |
| 3,422             | 3,407         | 1,978         | 2,331         | 2,228         | 1,537        | 857          |
| 4,172             | 4,202         | 2,666         | 3,005         | 2,919         | 2,116        | 1,348        |
| 44                | 34            | 40            | 27            | 23            | 21           | 12           |
| 76,263,964        | 64,462,805    | 41,638,100    | 36,685,881    | 30,731,741    | 14,945,348   | 11,293,268   |
| 4,553,237         | 4,271,069     | 2,901,621     | 1,950,209     | 1,690,520     | 1,422,815    | 840,144      |
| 103,583,566       | 90,089,219    | 59,047,824    | 48,387,138    | 40,874,862    | 23,482,236   | 16,334,130   |
| 9,600,867         | 7,368,757     | 5,678,772     | 3,980,460     | 3,303,750     | 1,900,302    | 1,440,690    |
| \$1.93            | \$1.96        | \$1.90        | \$1.58        | \$1.72        | \$1.73       | \$1.67       |
| \$14.35           | \$15.10       | \$17.19       | \$18.26       | \$22.70       | \$17.93      | \$14.38      |

## Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with the Company's Consolidated Financial Statements and Notes thereto.

### General

The Company's principal corporate objectives are the accumulation of crude oil and natural gas reserves for production and sale and the enhancement of the net present value of those reserves. Commencing in 1991, the Company began to emphasize the addition of reserves through increased development and exploration drilling activity. This emphasis on development and exploration drilling has led to additions of reserves in excess of the Company's production in each of the years 1996, 1997, and 1998. The Company's revenues are primarily comprised of oil and gas sales attributable to properties in which the Company owns a direct or indirect interest.

**Proved Oil and Gas Reserves.** At year-end 1998, the Company's total proved reserves were 436.1 Bcfe with a PV-10 Value of \$340.8 million. In 1998, the Company's proved natural gas reserves increased 38.1 Bcf (12%) and its proved oil reserves increased 6,099,007 barrels (78%) for a total of 74.7 Bcfe (21%). From 1996 to 1997, the Company's proved natural gas reserves increased 88.5 Bcf (39%) and its proved oil reserves increased 2,374,609 barrels (43%) for a total of 102.8 Bcfe (40%). The Company's additions to proved reserves from its development and exploration program were 73.9 Bcfe in 1998, 120.2 Bcfe in 1997, and 118.2 Bcfe in 1996. The Company's additions to proved reserves from acquisitions were 97.6 Bcfe in 1998, 33.8 Bcfe in 1997, and 3.3 Bcfe in 1996. A substantial portion of these reserves are proved undeveloped reserves comprising 45% of total proved reserves at year-end 1998, 40% of total proved reserves at year-end 1997, and 39% of total proved reserves at year-end 1996.

The change in the Standardized Measure of Discounted Future Net Cash Flows (see Supplemental Information to the Company's financial statements) and in the Estimated Present Value of Proved Reserves (see Business and Properties – Oil and Gas Reserves) from year-end 1997 to year-end 1998 is due to the addition of reserves through the Company's drilling activity (primarily in the AWP Olmos Field and the Austin Chalk trend) and the purchases of minerals in place (primarily in the Austin Chalk trend with the Toledo Bend Properties acquisition), offset by revisions of previous estimates and by the 20% decrease in year-end 1998 natural gas prices (\$2.23 per Mcf at year-end 1998 versus \$2.78 per Mcf at year-end 1997), and to the 29% decrease in year-end 1998 oil prices (\$11.23 per Bbl at year-end 1998, compared to \$15.76 per Bbl the prior year). While the Company's total proved reserves quantities at year-end 1998 increased by 21% over those at year-end 1997, the PV-10 Value of those reserves decreased 3% over the same period almost entirely due to pricing declines during 1998.

Under SEC guidelines, the Company's estimates of proved reserves are made using oil and gas sales prices in effect at year-end and are held constant throughout the life of the properties. The \$2.23 per Mcf and the \$11.23 per barrel prices used to calculate the PV-10 Value were year-end 1998 prices, which may not be indicative of future sales prices ultimately received.

### Liquidity and Capital Resources

**Net Cash Provided by Operating Activities.** In 1998, 1997, and 1996, the Company's operating activities provided net cash of \$54.2 million, \$55.3 million, and \$37.1 million, respectively. The slight decrease of \$1.1 million in 1998 was primarily due to the 54% increase in production volumes being more than offset by (a) the 25% decrease in average commodity prices received, (b) the associated 50% increase in oil and gas production costs, and (c) a decrease in interest income and an increase in interest expense as a result of all the net proceeds of the \$115.0 million Convertible Notes offering having been expended during 1997 and increased bank borrowings occurring during 1998. The 1997 increase of \$18.2 million was primarily due to an increase of \$16.5 million in cash flows from oil and gas sales and interest income.

**Existing Credit Facilities.** At December 31, 1998, the Company had outstanding borrowings of \$146.2 million under its new credit facility syndicated in August 1998. At December 31, 1997, the Company had \$7.9 million outstanding under its borrowing arrangements. Currently, the new credit facility consists of a \$250.0 million revolving line of credit with a \$170.0 million borrowing base. The borrowing base is redetermined at least every six months. The Company's \$250.0 million revolving credit facility includes, among other restrictions, requirements as to maintenance of certain minimum financial ratios (principally pertaining to working capital, debt, and equity ratios) and limitations on incurring other debt. The Company is currently in compliance with the provisions of this agreement, as amended in mid-March 1999 to modify the cash flow-to-debt covenant. The New Credit Facility will extend until August 2002.

**Working Capital.** The Company's working capital has increased from \$1.5 million at December 31, 1997, to \$3.8 million at December 31, 1998. This increase is primarily the result of an increase in oil and gas sales receivables resulting from the Company's increase in production volumes.

Due to the nature of the Company's business highlighted above, the individual components of working capital fluctuate considerably from period to period. The Company incurs significant working capital requirements in connection with its role as operator of approximately 836 wells and its drilling and acquisition activities. In this capacity, the Company is responsible for certain day-to-day cash management, including the collection and disbursement of oil and gas revenues and related expenses.

**Capital Expenditures.** The Company's capital expenditures were approximately \$183.8 million, \$132.0 million, and \$91.5 million for 1998, 1997, and 1996, respectively. The 1998 capital expenditures included (a) \$59.5 million (32% of 1998 capital expenditures) spent on producing properties acquisitions (almost all of which was for the Toledo Bend Properties acquisition), (b) \$54.8 million (30%) on developmental drilling (primarily in the AWP Olmos Field and Austin Chalk trend), (c) \$12.6 million (7%) on exploratory drilling, (d) \$34.7 million (19%) on domestic prospect costs (principally leasehold, seismic, and geological costs of unproven prospects for the Company's account, including \$15.2 million for leaseholds in the Toledo Bend Properties acquisition), (e) \$15.0 million (8%) for the purchase

of gas processing plants in the Toledo Bend Properties acquisition, (f) \$3.9 million (2%) invested in foreign business opportunities in New Zealand (\$2.9 million), Venezuela (\$0.4 million), and Russia (\$0.6 million), as described in Note 8 to the Company's financial statements, (g) \$2.2 million (1%) on field compression facilities, and (h) \$1.0 million (1%) on fixed assets.

In 1998, the Company participated in drilling 75 wells (61 development wells and 14 exploratory with 53 development successes and 5 exploratory successes). The steady growth in the Company's unproved property account (\$56.0 million), which is not being amortized, is indicative of the shift to a focus on drilling activity in recent years as the Company has acquired prospect acreage in or near its core areas (such as the acquisition of substantial leasehold positions in the Toledo Bend Properties acquisition) and in the pursuit of its New Zealand activities.

**Sources and Uses of Funds.** During 1997, the Company relied upon net proceeds from the sale of its \$115.0 million of Convertible Notes and its internally generated cash flows, along with \$7.9 million of bank borrowings to fund capital expenditures. During 1998, the Company relied upon \$138.3 million of bank borrowings, along with its internally generated cash flows of \$54.2 million, to fund its capital expenditures of \$183.8 million. Cash and working capital for 1999 are expected to be provided primarily through internally generated cash flows and limited bank borrowings.

Capital expenditures for 1999 are estimated to be substantially lower at approximately \$54.2 million. Approximately \$36.0 million of the 1999 budget is allocated to development and exploration drilling, primarily in its two core areas. The Company anticipates drilling 20 wells (15 development and five exploratory) in 1999. The remaining \$18.2 million is targeted principally for leasehold, seismic, and geological costs of unproved properties.

The Company believes that 1999's anticipated internally generated cash flows, together with limited borrowings under the new credit facility, will be sufficient to finance the costs associated with its currently budgeted 1999 capital expenditures.

## Results of Operations

**Revenues.** The Company's revenues in 1998 increased by 10% over revenues in 1997 and by 32% in 1997 over 1996 revenues, principally due to increases in oil and gas sales revenues.

The Company's net sales volumes in 1998 (including the volumetric production payment associated with each year's production) increased by 54% (13.6 Bcfe) over net sales volumes in 1997, while 1997 net sales volumes increased by 31% (6.0 Bcfe) over net sales volumes in 1996. Oil and gas sales revenues in 1998 increased by 16% (\$11.1 million) over those revenues for 1997, while in 1997 those revenues increased by 31% (\$16.2 million) over oil and gas sales revenues in 1996. Average prices for oil have declined from \$19.82 per Bbl in 1996 to \$17.59 per Bbl in 1997 to \$11.86 per Bbl in 1998, while average gas prices increased slightly from \$2.57 per Mcf in 1996 to \$2.68 per Mcf in 1997 and then decreased to \$2.08 per Mcf in 1998.

In 1998, the elements of the Company's \$11.1 million increase in oil and gas sales included (a) volume increases that added \$18.4 million of sales from the 6.9 Bcf increase in gas sales volumes and \$19.9 million of sales from the 1.1 million barrel increase in oil sales volumes and (b) price variances that had a \$27.2 million unfavorable impact on

sales due to the 22% decrease in average gas prices received (\$16.9 million), and the 33% decrease in average oil prices received (\$10.3 million).

In 1997, the Company's \$16.2 million increase in oil and gas sales included (a) volume increases that added \$14.5 million of sales from the 5.7 Bcf increase in gas sales volumes and \$1.0 million of sales from the 49,000 barrel increase in oil sales volumes, and (b) price variances that contributed \$2.2 million in increased sales from the increase in average gas prices received, offset somewhat by a \$1.5 million decrease in sales from the decrease in average oil prices received.

In 1998, the increases in oil and gas sales were primarily the result of production from the Toledo Bend Properties acquisition and secondarily from the Company's scaled-down drilling program, most notably from the Austin Chalk trend. The decisions to make this acquisition and to defer some drilling were both in response to market conditions. In 1997, the increases in oil and gas sales were primarily the result of production from the Company's accelerated drilling program, most notably from the Company's two primary development areas, the AWP Olmos Field and the Austin Chalk trend. The Company's 1998 oil and gas sales from the Toledo Bend Properties were \$24.2 million (none in 1997) from 11.6 Bcfe of net sales volumes, while sales from the rest of the Austin Chalk trend were \$14.6 million (\$12.9 million in 1997) from 7.0 Bcfe of net sales volumes (4.9 Bcfe in 1997), for an increase of 2.1 Bcfe. Sales in 1998 from the AWP Olmos Field were \$33.5 million (\$42.2 million in 1997) from 15.5 Bcfe of net sales volumes in both 1998 and 1997.

Revenues from oil and gas sales comprised 97%, 92%, and 94%, respectively, of total revenues for 1998, 1997, and 1996. The majority (73%, 83%, and 77%, respectively) of these oil and gas revenues in these periods were derived from the sale of the Company's gas production. The Toledo Bend Properties acquisition, which has a higher percentage of its production from oil (56% of 1998 production), has somewhat altered the Company's predominate gas production mix. Even though the Company has scaled back its 1999 capital expenditures budget, the Company expects oil and gas sales volumes to increase in 1999 when compared to 1998, primarily due to the full year of production from the Toledo Bend Properties. However, to the extent the Company curtails its development and exploration program as a result of the continued low price environment, oil and gas sales volumes will likely decrease in years subsequent to 1999.

**Costs and Expenses.** General and administrative expenses in 1998 increased \$0.3 million (9%) from the level of such expenses in 1997, while 1997 general and administrative expenses decreased \$0.6 million (15%) over 1996 levels. The small variances in these costs over the three-year period reflect the Company's ability to continue increasing its activities and reserves base without materially increasing such costs. The Company's general and administrative expenses per Mcfe produced have decreased in each of the past three years from \$0.21 per Mcfe produced in 1996 to \$0.14 per Mcfe produced in 1997 to \$0.10 per Mcfe produced in 1998. Supervision fees netted from general and administrative expenses for 1998, 1997, and 1996 were \$2.7 million, \$2.6 million, and \$2.2 million, respectively.

Depreciation, depletion, and amortization ("DD&A") has steadily increased (62% in 1998 and 47% in 1997), primarily due to the Company's reserves additions and associated costs and to the related sale of increased quantities of oil

and gas produced therefrom (54% in 1998 and 31% in 1997). The Company's DD&A rate per Mcfe of production was \$0.85 in 1996, \$0.95 in 1997, and \$1.01 in 1998, reflecting variations in the per unit cost of reserves additions.

Production costs in 1998 increased \$4.4 million (50%) over such expenses in 1997, while those expenses in 1997 increased \$2.6 million (43%) over 1996 costs. The increases in each of the periods primarily relate to the increases in the Company's oil and gas sales volumes. The Company's production costs per Mcfe produced were \$0.34 in 1998, \$0.35 in 1997, and \$0.32 in 1996. Supervision fees netted from production costs for 1998, 1997, and 1996 were \$2.7 million, \$2.6 million, and \$2.2 million, respectively.

Interest expense in both 1998 and 1997 on the Notes, including amortization of debt issuance costs, totaled \$7.5 million, compared to \$0.7 million on the Notes and \$1.0 million on the Debentures in 1996, while interest expense on the credit facilities, including commitment fees, in 1998 totaled \$5.6 million (\$0.1 million in 1997 and \$1.1 million in 1996), for a 1998 total interest expense of \$13.1 million (of which \$4.4 million was capitalized). The 1997 total interest expense was \$7.6 million (of which \$2.6 million was capitalized), while the 1996 total interest expense was \$2.8 million (of which \$2.1 million was capitalized). The Company capitalizes that portion of interest related to its exploration, partnership, and foreign business development activities. The increase in interest expense in 1998 was attributable to the increase in interest incurred on the amounts outstanding on its existing credit facility. The increase in interest expense in 1997 was attributable to the larger outstanding principal amount on the Notes (\$115.0 million) compared to the Debentures (\$28.75 million), offset to some degree by larger outstanding balances under the Company's credit facilities in 1996 and by the \$2.4 million in interest income earned in 1997 on the portion of the net proceeds of the Notes invested pending use.

A non-cash write-down of oil and gas properties occurred during the third quarter of 1998, as discussed in Note 1 to the Company's financial statements. Lower prices for both oil and natural gas at September 30, 1998, necessitated a pre-tax domestic full-cost ceiling write-down of \$77.2 million (\$50.9 million after tax). Concurrently, in the third quarter, the Company re-evaluated the timing of the recovery of its capitalized unproved properties costs in Russia due to economical and political uncertainty and impaired its total investment of \$10.8 million. In addition, the international economic uncertainty and currency concerns in Venezuela, combined with the price volatility and severe tightening of international credit markets, also caused the Company to impair its capitalized unproved properties costs in Venezuela of \$2.8 million. The re-evaluation of the unproved properties costs in these two countries resulted in a separate non-cash pre-tax charge to earnings of \$13.6 million (\$9.0 million after tax). The combination of the non-cash full-cost ceiling write-down and the non-cash foreign impairment charges resulted in a combined non-cash pre-tax charge to earnings of \$90.8 million (\$59.9 million after tax).

The Company's full-cost ceiling cushion at December 31, 1998, was approximately \$25.0 million. If during 1999, oil and gas prices decrease appreciably from year-end 1998 prices, then the Company might be required to make another ceiling test write-down.

**Net Income.** Before the non-cash write-down of oil and gas properties in 1998, net income of \$11.7 million and basic earnings per share of \$0.71 were 48% and 47% lower, respectively, than net income of \$22.3 million and basic

earnings per share of \$1.35 in the same period for 1997. This decrease primarily reflected the effect of the 33% and 22% decreases in oil and gas prices, respectively, while costs and expenses increased in proportion to the 54% increase in production volumes discussed above.

Net income of \$22.3 million and basic earnings per share of \$1.35 for 1997 were 17% and 6% higher, respectively, than net income of \$19.0 million and basic earnings per share of \$1.27 in 1996. This increase in net income primarily reflected the effect of a 31% increase in oil and gas sales revenues as a result of a 36% increase in natural gas production, an 8% increase in crude oil production, and a slight 4% increase in gas prices received, offset somewhat by an 11% decrease in oil prices received. The lower percentage increase in basic earnings per share reflects a 10% increase in weighted average shares outstanding in 1997 as a result of the conversion of the Debentures into 2.34 million shares of common stock in the third quarter of 1996.

**Year 2000.** The Year 2000 issue results from computer programs and embedded computer chips with date fields that cannot distinguish between the years 1900 and 2000. The Company is currently implementing the steps necessary to make the Company's operations capable of addressing the Year 2000. These steps include upgrading, testing, and certifying its computer systems and field operation services and obtaining Year 2000 compliance certification from the Company's critical business suppliers, customers, vendors, and other service providers. The Company formed a task force during 1998 to address the Year 2000 issue and prepare the Company's business systems for the Year 2000. By mid-1999 the Company expects the mission critical systems to be either replaced or updated and testing to be virtually completed.

The Company's business systems are almost entirely comprised of off-the-shelf software. Most of the necessary changes in computer instructional code can be made by upgrading such software. The Company is currently in the process of either upgrading the off-the-shelf software or receiving certification as to Year 2000 compliance from vendors or third-party consultants. A testing phase is being conducted as the software is updated or certified and is expected to be completed by mid-1999.

The Company does not believe that costs incurred to address the Year 2000 issue with respect to its business systems will have a material effect on the Company's results of operations or its liquidity and financial condition. The estimated total cost to address Year 2000 issues is projected to be less than \$150,000, most of which will be spent during the testing phase.

The failure to correct a material Year 2000 problem could result in an interruption or failure of certain normal business activities or operations. Based on activities to date, the Company believes that it will be able to resolve any Year 2000 problems concerning its financial and administrative systems. It is undeterminable how all the aspects of the Year 2000 issue will impact the Company; however, field operations and the myriad of peripheral technical applications which perform the Company's core business functions of oil and gas exploration are primarily non-information technology systems which are not date specific and are predicted to perform correctly. The most reasonably likely worst case scenario, therefore, would involve a prolonged disruption of external power sources upon which core equipment relies, resulting in a substantial decrease in the Company's oil and gas production activities. Although the Company maintains

limited on-site secondary power supplies such as generators, it is not economically feasible to maintain a secondary power supply to fully replace primary power; therefore, a prolonged interruption could materially affect the Company's operations, liquidity or capital resources. In addition, pipeline operators to whom the Company sells natural gas, as well as other customers and suppliers, could be prone to Year 2000 problems that could not be assessed or detected by the Company. The Company is contacting its major purchasers, customers, suppliers, financial institutions and others with whom it conducts business to determine whether they will be able to resolve in a timely manner any Year 2000 problems directly affecting the Company and to inform them of the Company's internal assessment of its Year 2000 review. There can be no assurance that such third parties will not fail to appropriately address their Year 2000 issues or will not themselves suffer a Year 2000 disruption that could have a material adverse effect on the Company's business, financial condition, or operating results. Based upon these responses and any problems that arise during the testing phase, contingency plans or back-up systems would be determined and addressed. The Company has utilized, and will continue to utilize, both internal and external resources to complete tasks and perform testing necessary to address the Year 2000 problem.

#### **Forward Looking Statements**

The statements contained in this Annual Report on Form 10-K ("Annual Report") that are not historical facts are forward-looking statements as that term is defined in Section 21E of the Securities and Exchange Act of 1934, as amended, and therefore involve a number of risks and uncertainties. Such forward-looking statements may be or may concern,

among other things, capital expenditures, drilling activity, development activities, cost savings, production efforts and volumes, hydrocarbon reserves, hydrocarbon prices, liquidity, regulatory matters, Year 2000 issues, and competition. Such forward-looking statements generally are accompanied by words such as "plan," "budget," "estimate," "expect," "predict," "anticipate," "projected," "should," "believe," or other words that convey the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates and assumptions and is subject to a number of risks and uncertainties that could significantly affect current plans, anticipated actions, the timing of such actions and the Company's financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates, or assumptions expressed in or implied by any forward-looking statements made by or on behalf of the Company, including those regarding the Company's financial results, levels of oil and gas production or revenues, capital expenditures, and capital resource activities. Among the factors that could cause actual results to differ materially are: fluctuations of the prices received or demand for the Company's oil and natural gas; the uncertainty of drilling results and reserve estimates; operating hazards; requirements for capital; general economic conditions; competition and government regulations; as well as the risks and uncertainties discussed in this Annual Report, including, without limitation, the portions referenced above and the uncertainties set forth from time to time in the Company's other public reports, filings, and public statements. Also, because of the volatility in oil and gas prices and other factors, interim results are not necessarily indicative of those for a full year.

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## **Item 7A. Quantitative and Qualitative Disclosures About Market Risk**

**Commodity Risk.** The Company's major market risk exposure is the commodity pricing applicable to its oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for crude oil and spot prices applicable to natural gas. The effects of such pricing volatility have been discussed above, and such volatility is expected to continue.

To mitigate some of this risk, the Company engages periodically in certain limited hedging activities but only to the extent of buying protection price floors for portions of its and the Company managed limited partnerships' oil and gas production. Costs and any benefits derived from these price floors are accordingly recorded as a reduction or increase, as applicable, in oil and gas sales revenue and were not significant for any year presented. The costs to purchase put options are amortized over the option period. The Company does not hold or issue derivative instruments for trading purposes. The costs related to 1998 hedging activities totaled approximately \$377,000, with benefits of approximately \$101,000 being received, resulting in a net cash outlay of approximately \$276,000 or \$0.007 per Mcfe. The costs related to the open contracts totaled approximately \$252,000 and had a market value of \$267,000 as of December 31, 1998. The costs related to 1997 hedging activities totaled approximately \$1,052,000 (\$800,000 in 1996) with benefits of approximately \$439,000 (none in 1996) being received, resulting in a net cash outlay of approximately \$613,000 or \$0.014 (\$0.041 in 1996) per Mcfe.

**Interest Rate Risk.** The Company considers its interest rate risk exposure to be minimal as a result of a fixed interest rate on the \$115,000,000 Convertible Notes. In regards to its New Credit Facility, the result of a 10% fluctuation in short-term interest rates (approximately 63 basis points) would impact 1999 cash flow by approximately \$0.9 million.

**Financial Instruments & Debt Maturities.** The Company's financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and convertible notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 1998 and 1997 and were determined based upon interest rates currently available to the Company for borrowings with similar terms. The fair values of the convertible notes were \$81.4 million and \$113.6 million at December 31, 1998 and 1997, respectively, and were based on quoted market prices as of the respective dates. Bank borrowings under the Company's new credit facility mature on August 18, 2002. The Company's \$115.0 million convertible notes mature on November 15, 2006.

## Item 8. Financial Statements and Supplementary Data

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## Report of Independent Public Accountants

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To the Stockholders and Board of Directors of Swift Energy Company:

We have audited the accompanying consolidated balance sheets of Swift Energy Company (a Texas corporation) and subsidiaries as of December 31, 1998 and 1997, and the related consolidated statements of income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 1998. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Swift Energy Company and subsidiaries as of December 31, 1998 and 1997, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1998, in conformity with generally accepted accounting principles.

Houston, Texas  
February 10, 1999

ARTHUR ANDERSEN LLP

# Consolidated Balance Sheets

Swift Energy Company and Subsidiaries

December 31,

1998 1997

## ASSETS

### Current Assets:

|  |                   |                   |
|--|-------------------|-------------------|
| Cash and cash equivalents                          | \$ 1,630,649      | \$ 2,047,332      |
| Accounts receivable—                               |                   |                   |
| Oil and gas sales                                  | 12,764,568        | 11,143,033        |
| Associated limited partnerships and joint ventures | 10,058,239        | 8,498,702         |
| Joint interest owners                              | 9,767,940         | 7,357,660         |
| Other current assets                               | 1,025,035         | 935,059           |
| <b>Total Current Assets</b>                        | <b>35,246,431</b> | <b>29,981,786</b> |

### Property and Equipment:

|  |               |              |
|--|---------------|--------------|
| Oil and gas, using full-cost accounting                      |               |              |
| Proved properties being amortized                            | 497,296,068   | 326,836,431  |
| Unproved properties not being amortized                      | 56,041,886    | 41,839,809   |
|  | 553,337,954   | 368,676,240  |
| Furniture, fixtures, and other equipment                     | 7,098,305     | 6,242,927    |
|  | 560,436,259   | 374,919,167  |
| Less — Accumulated depreciation, depletion, and amortization | (200,713,621) | (70,700,240) |
|  | 359,722,638   | 304,218,927  |

### Other Assets:

|  |                       |                       |
|--|-----------------------|-----------------------|
| Receivables from associated limited partnerships, net of current portion | 3,170,067             | 433,444               |
| Limited partnership formation and marketing costs                        | 917,189               | 297,219               |
| Deferred income taxes  | 254,984               | —                     |
| Deferred charges   | 4,333,958             | 4,184,014             |
|  | 8,676,198             | 4,914,677             |
|  | <b>\$ 403,645,267</b> | <b>\$ 339,115,390</b> |

## LIABILITIES AND STOCKHOLDERS' EQUITY

### Current Liabilities:

|  |                   |                   |
|--|-------------------|-------------------|
| Accounts payable and accrued liabilities   | \$ 18,639,649     | \$ 16,518,240     |
| Payable to associated limited partnerships | 380,692           | 3,245,445         |
| Undistributed oil and gas revenues         | 12,394,713        | 8,753,979         |
| <b>Total Current Liabilities</b>           | <b>31,415,054</b> | <b>28,517,664</b> |

|                       |             |             |
|-----------------------|-------------|-------------|
| Convertible Notes     | 115,000,000 | 115,000,000 |
| Bank Borrowings       | 146,200,000 | 7,915,000   |
| Deferred Revenues     | 1,667,574   | 2,927,656   |
| Deferred Income Taxes | —           | 25,354,150  |

### Commitments and Contingencies

### Stockholders' Equity:

|  |                       |                       |
|--|-----------------------|-----------------------|
| Preferred stock, \$.01 par value, 5,000,000 shares authorized, none outstanding  | —                     | —                     |
| Common stock, \$.01 par value, 35,000,000 shares authorized, 16,972,517 and 16,846,956 shares issued, and 16,291,242 and 16,459,156 shares outstanding, respectively | 169,725               | 168,470               |
| Additional paid-in capital   | 148,901,270           | 147,542,977           |
| Treasury stock held, at cost, 681,275 and 387,800 shares, respectively   | (11,841,884)          | (8,519,665)           |
| Unearned ESOP compensation   | —                     | (150,055)             |
| Retained earnings (deficit)  | (27,866,472)          | 20,359,193            |
|  | 109,362,639           | 159,400,920           |
|  | <b>\$ 403,645,267</b> | <b>\$ 339,115,390</b> |

See accompanying notes to Consolidated Financial Statements.

# Consolidated Statements of Income

Swift Energy Company and Subsidiaries

Year Ended December 31,

|   | 1998                          | 1997                        | 1996                        |
|---|-------------------------------|-----------------------------|-----------------------------|
| <b>Revenues:</b>  |                               |                             |                             |
| Oil and gas sales . . . . .                                 | \$ 80,067,837                 | \$ 69,015,189               | \$ 52,770,672               |
| Fees from limited partnerships and joint ventures . . . . . | 333,940                       | 745,856                     | 937,238                     |
| Interest income . . . . .                                   | 107,374                       | 2,395,406                   | 433,352                     |
| Other, net . . . . .  | <u>1,960,070</u>              | <u>2,555,729</u>            | <u>2,156,764</u>            |
|   | <u>82,469,221</u>             | <u>74,712,180</u>           | <u>56,298,026</u>           |
| <b>Costs and Expenses:</b>                                  |                               |                             |                             |
| General and administrative, net of reimbursement . . . . .  | 3,853,812                     | 3,523,604                   | 4,149,964                   |
| Depreciation, depletion, and amortization . . . . .         | 39,343,187                    | 24,247,142                  | 16,526,379                  |
| Oil and gas production . . . . .                            | 13,138,980                    | 8,778,876                   | 6,141,941                   |
| Interest expense, net . . . . .                             | 8,752,195                     | 5,032,952                   | 693,959                     |
| Write-down of oil and gas properties . . . . .              | <u>90,772,628</u>             | <u>—</u>                    | <u>—</u>                    |
|   | <u>155,860,802</u>            | <u>41,582,574</u>           | <u>27,512,243</u>           |
| Income (Loss) Before Income Taxes . . . . .                 | (73,391,581)                  | 33,129,606                  | 28,785,783                  |
| Provision (Benefit) for Income Taxes . . . . .              | <u>(25,166,377)</u>           | <u>10,819,417</u>           | <u>9,760,333</u>            |
| Net Income (Loss) . . . . .                                 | <u><u>\$ (48,225,204)</u></u> | <u><u>\$ 22,310,189</u></u> | <u><u>\$ 19,025,450</u></u> |
| <b>Per Share Amounts—</b>                                   |                               |                             |                             |
| Basic . . . . .   | <u>\$ (2.93)</u>              | <u>\$ 1.35</u>              | <u>\$ 1.27</u>              |
| Diluted . . . . .   | <u>\$ (2.93)</u>              | <u>\$ 1.26</u>              | <u>\$ 1.25</u>              |
| Weighted Average Shares Outstanding . . . . .               | <u>16,436,972</u>             | <u>16,492,856</u>           | <u>15,000,901</u>           |

See accompanying Notes to Consolidated Financial Statements.

# Consolidated Statements of Stockholders' Equity

Swift Energy Company and Subsidiaries

|   | Common<br>Stock <sup>1</sup> | Additional<br>Paid-in<br>Capital | Treasury<br>Stock | Unearned<br>ESOP<br>Compen-<br>sation | Retained<br>Earnings<br>(Deficit) | Total          |
|---|------------------------------|----------------------------------|-------------------|---------------------------------------|-----------------------------------|----------------|
| Balance, December 31, 1995                        | \$ 125,097                   | \$ 71,133,979                    | \$ —              | \$ —                                  | \$ 22,086,889                     | \$ 93,345,965  |
| Stock issued for benefit plans<br>(30,015 shares) | 300                          | 347,345                          | —                 | —                                     | —                                 | 347,645        |
| Stock options exercised<br>(257,207 shares)       | 2,572                        | 2,630,959                        | —                 | —                                     | —                                 | 2,633,531      |
| Employee stock purchase plan<br>(36,387 shares)   | 364                          | 272,178                          | —                 | —                                     | —                                 | 272,542        |
| Loan to ESOP for purchase<br>of shares            | —                            | —                                | —                 | (568,750)                             | —                                 | (568,750)      |
| Allocation of ESOP shares                         | —                            | 5,382                            | —                 | 47,396                                | —                                 | 52,778         |
| Debenture conversion (2,343,108<br>shares)        | 23,431                       | 27,629,018                       | —                 | —                                     | —                                 | 27,652,449     |
| Net income  | —                            | —                                | —                 | —                                     | 19,025,450                        | 19,025,450     |
| Balance, December 31, 1996                        | \$ 151,764                   | \$ 102,018,861                   | \$ —              | \$ (521,354)                          | \$ 41,112,339                     | \$ 142,761,610 |
| Stock issued for benefit plans<br>(12,227 shares) | 122                          | 371,359                          | —                 | —                                     | —                                 | 371,481        |
| Stock options exercised (137,155<br>shares)       | 1,372                        | 1,613,071                        | —                 | —                                     | —                                 | 1,614,443      |
| Employee stock purchase plan<br>(26,551 shares)   | 266                          | 403,145                          | —                 | —                                     | —                                 | 403,411        |
| 10% stock dividend (1,494,606<br>shares)          | 14,946                       | 43,048,389                       | —                 | —                                     | (43,063,335)                      | —              |
| Allocation of ESOP shares                         | —                            | 88,152                           | —                 | 371,299                               | —                                 | 459,451        |
| Purchase of 387,800 shares as<br>treasury stock   | —                            | —                                | (8,519,665)       | —                                     | —                                 | (8,519,665)    |
| Net income  | —                            | —                                | —                 | —                                     | 22,310,189                        | 22,310,189     |
| Balance, December 31, 1997                        | \$ 168,470                   | \$ 147,542,977                   | \$ (8,519,665)    | \$ (150,055)                          | \$ 20,359,193                     | \$ 159,400,920 |
| Stock issued for benefit plans<br>(20,032 shares) | 200                          | 367,058                          | —                 | —                                     | —                                 | 367,258        |
| Stock options exercised (84,757<br>shares)        | 847                          | 735,746                          | —                 | —                                     | —                                 | 736,593        |
| Employee stock purchase plan<br>(20,756 shares)   | 208                          | 317,340                          | —                 | —                                     | —                                 | 317,548        |
| Stock dividend adjustment<br>(16 shares)          | —                            | 461                              | —                 | —                                     | (461)                             | —              |
| Allocation of ESOP shares                         | —                            | (62,312)                         | —                 | 150,055                               | —                                 | 87,743         |
| Purchase of 293,475 shares as<br>treasury stock   | —                            | —                                | (3,322,219)       | —                                     | —                                 | (3,322,219)    |
| Net loss  | —                            | —                                | —                 | —                                     | (48,225,204)                      | (48,225,204)   |
| Balance, December 31, 1998                        | \$ 169,725                   | \$ 148,901,270                   | \$ (11,841,884)   | \$ —                                  | \$ (27,866,472)                   | \$ 109,362,639 |

<sup>1</sup>\$0.01 par value

See accompanying notes to Consolidated Financial Statements.

# Consolidated Statements of Cash Flows

Swift Energy Company and Subsidiaries

Year Ended December 31,

|  | 1998                 | 1997                 | 1996                 |
|--|----------------------|----------------------|----------------------|
| <b>Cash Flows from Operating Activities:</b>   |                      |                      |                      |
| Net income (loss) .....  | \$ (48,225,204)      | \$ 22,310,189        | \$ 19,025,450        |
| Adjustments to reconcile net income to net cash provided<br>by operating activities—                     |                      |                      |                      |
| Depreciation, depletion, and amortization .....  | 39,343,187           | 24,247,142           | 16,526,379           |
| Write-down of oil and gas properties .....   | 90,772,628           | —                    | —                    |
| Deferred income taxes .....  | (25,609,134)         | 10,060,193           | 8,449,283            |
| Deferred revenue amortization related to production payment .....  | (1,248,800)          | (1,449,808)          | (1,670,172)          |
| Other .....  | 478,470              | 786,917              | 140,047              |
| Change in assets and liabilities—  |                      |                      |                      |
| Increase in accounts receivable .....  | (2,129,360)          | (204,475)            | (5,008,592)          |
| Increase (decrease) in accounts payable and accrued liabilities,<br>excluding income taxes payable ..... | 689,347              | (564,323)            | (444,966)            |
| Increase in income taxes payable .....   | 177,883              | 70,130               | 85,149               |
| <u>Net Cash Provided by Operating Activities .....</u>   | <u>54,249,017</u>    | <u>55,255,965</u>    | <u>37,102,578</u>    |
| <b>Cash Flows from Investing Activities:</b>   |                      |                      |                      |
| Additions to property and equipment .....  | (183,815,927)        | (131,967,444)        | (91,487,176)         |
| Proceeds from the sale of property and equipment .....   | 1,533,112            | 3,369,982            | 2,247,799            |
| Net cash distributed as operator of oil and gas properties .....   | (5,933,171)          | (1,829,008)          | (2,074,104)          |
| Net cash received (distributed) as operator of partnerships and<br>joint ventures .....                  | (1,559,537)          | (2,102,553)          | 11,284,793           |
| Limited partnership formation and marketing costs .....  | (619,970)            | —                    | —                    |
| Other .....  | (113,716)            | (259,255)            | 840                  |
| <u>Net Cash Used in Investing Activities .....</u>   | <u>(190,509,209)</u> | <u>(132,788,278)</u> | <u>(80,027,848)</u>  |
| <b>Cash Flows from Financing Activities:</b>   |                      |                      |                      |
| Proceeds from convertible notes .....  | —                    | —                    | 115,000,000          |
| Net proceeds from bank borrowings .....  | 138,285,000          | 7,915,000            | —                    |
| Net proceeds from issuances of common stock .....  | 1,421,399            | 2,389,336            | 3,264,482            |
| Purchase of treasury stock .....   | (3,322,219)          | (8,519,665)          | —                    |
| Loan to ESOP for purchase of shares .....  | —                    | —                    | (568,750)            |
| Payments of debt issuance costs .....  | (540,671)            | —                    | (4,550,000)          |
| <u>Net Cash Provided by Financing Activities .....</u>   | <u>135,843,509</u>   | <u>1,784,671</u>     | <u>113,145,732</u>   |
| Net Increase (Decrease) in Cash and Cash Equivalents .....   | \$ (416,683)         | \$ (75,747,642)      | \$ 70,220,462        |
| Cash and Cash Equivalents at Beginning of Year .....   | 2,047,332            | 77,794,974           | 7,574,512            |
| Cash and Cash Equivalents at End of Year .....   | <u>\$ 1,630,649</u>  | <u>\$ 2,047,332</u>  | <u>\$ 77,794,974</u> |
| <i>Supplemental Disclosures of Cash Flows Information:</i>   |                      |                      |                      |
| Cash paid during year for interest, net of amounts capitalized .....                                     | \$ 8,343,445         | \$ 4,638,308         | \$ 831,516           |
| Cash paid during year for income taxes .....   | \$ 36,286            | \$ 381,514           | \$ 676,920           |

See accompanying notes to Consolidated Financial Statements.

# Notes to Consolidated Financial Statements

## Swift Energy Company and Subsidiaries

### 1. Summary of Significant Accounting Policies

**Principles of Consolidation.** The accompanying consolidated financial statements include the accounts of Swift Energy Company (Swift) and its wholly owned subsidiaries (collectively referred to as the "Company"), which are engaged in the exploration, development, acquisition, and operation of oil and natural gas properties, with particular emphasis on U.S. onshore natural gas reserves. The Company also has oil and gas activities in New Zealand, Venezuela, and Russia. The Company's investments in associated oil and gas partnerships and its joint ventures are accounted for using the proportionate consolidation method, whereby the Company's proportionate share of each entity's assets, liabilities, revenues, and expenses is included in the appropriate classifications in the consolidated financial statements. Intercompany balances and transactions have been eliminated in preparing the consolidated statements. In the second quarter of 1998, the Company began netting supervision fees against general and administrative expenses and oil and gas production costs. This reclassification has been made for all periods presented. Certain other reclassifications have been made to prior year amounts to conform to the current year presentation.

**Use of Estimates.** The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from estimates.

**Property and Equipment.** The Company follows the "full-cost" method of accounting for oil and gas property and equipment costs. Under this method of accounting, all productive and nonproductive costs incurred in the acquisition, exploration, and development of oil and gas reserves are capitalized. Under the full-cost method of accounting, such costs may be incurred both prior to or after the acquisition of a property and include lease acquisitions, geological and geophysical services, drilling, completion, equipment, and certain general and administrative costs directly associated with acquisition, exploration, and development activities. Interest costs related to unproved properties are also capitalized to unproved oil and gas properties. The Company's management believes this capitalization of such costs is appropriate under full-cost accounting rules. General and administrative costs related to production and general overhead are expensed as incurred.

No gains or losses are recognized upon the sale or disposition of oil and gas properties, except in transactions that involve a significant amount of reserves. The proceeds from the sale of oil and gas properties are generally treated as a reduction of oil and gas property costs. Fees from associated oil and gas exploration and development limited partnerships are credited to oil and gas property costs to the extent they do not represent reimbursement of general and administrative expenses currently charged to expense.

Future development, site restoration, and dismantlement and abandonment costs, net of salvage values, are estimated on a property-by-property basis based on current economic conditions and are amortized to expense as the Company's capitalized oil and gas property costs are amortized. The

Company's properties are all onshore, and historically the salvage value of the tangible equipment offsets the Company's site restoration and dismantlement and abandonment costs. The Company expects that this relationship will continue in the future.

The Company computes the provision for depreciation, depletion, and amortization of oil and gas properties on the unit-of-production method. Under this method, the Company computes the provision by multiplying the total unamortized costs of oil and gas properties—including future development, site restoration, and dismantlement and abandonment costs, but excluding costs of unproved properties—by an overall rate determined by dividing the physical units of oil and gas produced during the period by the total estimated units of proved oil and gas reserves. This calculation is done on a country-by-country basis for those countries with oil and gas production. The Company currently has production in the United States only. All other equipment is depreciated by the straight-line method at rates based on the estimated useful lives of the property. Repairs and maintenance are charged to expense as incurred. Renewals and betterments are capitalized.

The cost of unproved properties not being amortized is assessed quarterly, on a country-by-country basis, to determine whether such properties have been impaired. Domestically, any impairment assessed is added to the cost of proved properties being amortized. To the extent costs accumulated in the Company's international initiatives are determined by management to be costs that will not result in the addition of proved reserves, any impairment is charged to income. In determining whether such costs should be impaired, the Company's management evaluates, among other factors, current oil and gas industry conditions, international economic conditions, capital availability, foreign currency exchange rates, the political stability in the countries in which the Company has an investment, and available geological and geophysical information.

*Domestic Properties.* At the end of each quarterly reporting period, the unamortized cost of oil and gas properties, net of related deferred income taxes, is limited to the sum of the estimated future net revenues from proved properties using current period-end prices, discounted at 10%, and the lower of cost or fair value of unproved properties, adjusted for related income tax effects ("Ceiling Test"). This calculation is done on a country-by-country basis for those countries with proved reserves. Currently, the Company has proved reserves in the United States only.

The calculation of the Ceiling Test and provision for depreciation, depletion, and amortization is based on estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production, timing, and plan of development. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserves estimates are often different from the quantities of oil and gas that are ultimately recovered.

As a result of low oil and gas prices at September 30, 1998, the Company reported a non-cash write-down on a

before-tax basis of \$77.2 million (\$50.9 million after tax) on its domestic properties.

**Foreign Properties.** In addition, during the third quarter of 1998, as it does every reporting period, the Company evaluated all of its foreign unevaluated properties (a detailed description of which is included in Note 8 to the Company's financial statements), especially in light of the then increased volatility in the oil and gas markets, international uncertainty, and turmoil in the world capital markets.

The increased volatility in the oil and gas markets affected the Company's cash flows available for further exploration and forced the Company to scale back its capital expenditures budget. All of this was further accentuated in Venezuela by the economic crisis there, the results of which were to diminish the availability of financing in international markets for Venezuelan projects and to worsen Venezuelan currency problems. *Petroleos de Venezuela, S.A.* layoffs, threatened oil worker strikes, reduced OPEC production allocations, and other third quarter 1998 events highlight the problems that the oil and gas industry is encountering in Venezuela. As a result of these and other factors, in the third quarter of 1998, the Company decided to impair all \$2.8 million of costs related to its Venezuelan oil and gas exploration activities.

In addition, in the third quarter of 1998, the Company impaired all \$10.8 million of costs relating to its Russian activities. This impairment is attributed not only to the volatility in the oil and gas markets and the severe tightening of international credit markets discussed above, but also to the increased political instability in Russia and the August 1998 collapse of the Russian currency. The Company believed that the economic and political situation would result in the lack of capital to develop these reserves underlying the Company's net profits interest in the near term. Although the Company continues to believe that its net profits interest is legally enforceable under international law, for all these reasons the Company does not believe that realistically it will be able to recover its investment in Russia in the foreseeable future. Because of this, the Company determined that it no longer had a reasonable basis to continue capitalization of the costs in its Russia cost center.

The combination of the third-quarter domestic full-cost ceiling write-down and foreign activities impairment charges reduced before-tax earnings by \$90.8 million (\$59.9 million after tax). Since such impairment, any costs incurred in Venezuela and Russia have been charged to income.

Also, during the fourth quarter of 1998, the Company's \$0.4 million portion of drilling costs associated with an unsuccessful exploratory well drilled by another operator in New Zealand was charged to income as depreciation, depletion, and amortization costs.

**Oil and Gas Revenues.** Gas revenues are reported using the entitlement method in which the Company recognizes its ownership interest in natural gas production as revenue. If the Company's sales exceed its ownership share of production, the differences are reported as deferred revenue. Natural gas balancing receivables are reported when the Company's ownership share of production exceeds sales. As of December 31, 1998, the Company did not have any material natural gas imbalances.

**Deferred Charges.** Legal and accounting fees, underwriting fees, printing costs, and other direct expenses associated with the public offering in November 1996 of the Company's 6.25% Convertible Subordinated Notes (the "Notes") have been capitalized and are being amortized over the life of the Notes, which mature on November 15,

2006. The balance of these issuance costs at December 31, 1998 was \$3,826,864, net of accumulated amortization of \$723,136. The issuance costs associated with its new \$250.0 million revolving credit facility (the "New Credit Facility"), which closed in August 1998, have been capitalized and are being amortized over the life of the facility, which will extend until August 2002. The balance of these issuance costs at December 31, 1998, was \$507,094, net of accumulated amortization of \$51,600.

**Limited Partnerships and Joint Ventures.** Between 1984 and 1995, the Company formed limited partnerships and joint ventures for the purpose of acquiring interests in producing oil and gas properties and, since 1993, partnerships engaged in drilling for oil and gas reserves. The Company serves as managing general partner or manager of these entities.

The Company acquired producing oil and gas properties and transferred those properties to the partnership entities which invested in producing oil and gas properties. These transfers were at cost, including interest, other carrying costs, closing costs, and screening and evaluation costs of properties not acquired, or, in certain instances, at fair market value based upon the opinion of an independent expert. These costs were reduced by net operating revenues from the effective date of the acquisition to the date of transfer to these entities. Such net operating revenue amounts totaled approximately \$100,000 and \$300,000 in 1997 and 1996, respectively. With the acquisitions made in 1997, the Company fulfilled its responsibility of acquiring properties for such partnerships, as these partnerships are fully invested in properties.

Commencing in September 1993, the Company began offering, on a private placement basis, general and limited partnership interests in limited partnerships to be formed to drill for oil and gas. As managing general partner, the Company pays for all front-end costs incurred in connection with these offerings, for which the Company receives an interest in the partnerships. Through December 31, 1998, approximately \$66.1 million had been raised in thirteen partnerships, one each formed in 1993 and 1994; three each in 1995, 1996, and 1997; and two in 1998. In June and October 1998, the Company closed the twelfth and thirteenth partnerships with total subscriptions of approximately \$3.2 million and \$4.3 million, respectively. Costs of syndication and qualification of these limited partnerships incurred by the Company have been deferred. Under the current private limited partnership offerings, selling and formation costs borne by the Company serve as the Company's general partner contribution to such partnerships.

During 1996, the limited partners in 18 partnerships, which had been in operation over nine years and had produced a substantial majority of their reserves, voted to sell their remaining properties and liquidate the limited partnerships. Of these partnerships, 10 were the earliest public income partnerships formed between 1984 and 1986. In early 1997, eight private drilling partnerships formed between 1979 and 1985 were liquidated. During 1997, the limited partners in an additional 11 partnerships, formed in 1990 and 1991, voted to sell their properties and liquidate the limited partnerships, which occurred in June 1998.

In October 1998, the Company notified investors in 63 Company-managed partnerships, formed between 1986 and 1994, that it had delayed calling investor meetings to consider its purchase of all of the oil and gas properties owned by these partnerships, which was proposed in March 1998. This decision principally reflected significant market changes that had occurred during the long period necessary for

regulatory review of soliciting materials, the age of the third-party appraisals of these partnership properties, and the much publicized weakness in both the equity and debt markets for energy companies. During the last six months, the weakness in oil and natural gas prices has deepened, creating concern over the appropriateness of selling properties at this time. The Company expects to continue to re-evaluate the status and operation of these partnerships, whether to propose some form of liquidating transaction and, if so, when and in what form.

**Hedging Activities.** The Company's revenues are primarily the result of sales of its oil and natural gas production. Market prices of oil and natural gas may fluctuate and adversely affect operating results. To mitigate some of this risk, the Company engages periodically in certain limited hedging activities, but only to the extent of buying protection price floors for portions of its and the limited partnerships' oil and natural gas production. Costs and any benefits derived from these price floors are accordingly recorded as a reduction or an increase, as applicable, in oil and gas sales revenue and were not significant for any year presented. The costs to purchase put options are amortized over the option period. The costs related to 1998 hedging activities totaled approximately \$377,000 with benefits of approximately \$101,000 being received, resulting in a net cash outlay of approximately \$276,000 or \$0.007 per Mcf. The costs related to the open contracts as of December 31, 1998, totaled approximately \$252,000 and had a fair market value of \$267,000.

**Income Taxes.** The Company accounts for income taxes using the liability method, and deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax bases of assets and liabilities given the provisions of the enacted tax laws.

**Deferred Revenues.** In May 1992, the Company purchased interests in certain wells using funds provided by the Company's sale of a volumetric production payment in these properties to Enron. Under the production payment agreement, the Company is required to deliver to Enron approximately 9.5 Bcf over an eight-year period, or for such longer period as is necessary to deliver a specified heating equivalent quantity at an average price of \$1.115 per MMBtu. The Company receives all proceeds from sale of excess gas at current market prices plus the proceeds from sale of oil or condensate. Volumes remaining to be delivered through October 2000 under the volumetric production payment were approximately 1.1 Bcf at December 31, 1998, and were not included in the Company's proved reserves. Net proceeds from the sale of the production payment were recorded as deferred revenues. Deliveries under the production payment agreement are recorded as oil and gas sales revenues and a corresponding reduction of deferred revenues.

**Cash and Cash Equivalents.** The Company considers all highly liquid debt instruments with an initial maturity of three months or less to be cash equivalents.

**Credit Risk Due to Certain Concentrations.** The Company extends credit, primarily in the form of monthly oil and gas sales and joint interest owners receivables, to various companies in the oil and gas industry, which results in a concentration of credit risk. The concentration of credit risk may be affected by changes in economic or other conditions and may accordingly impact the Company's overall credit risk. However, the Company believes that the risk of these unsecured receivables is mitigated by the size,

reputation, and nature of the companies to which the Company extends credit. During 1998, oil and gas sales to subsidiaries of PG&E Energy Trading Corporation and Aquila Southwest Pipeline Corporation were \$13.0 million (16.2% of oil and gas sales) and \$8.0 million (10.0%), respectively. In 1997, oil and gas sales to PG&E Energy Trading Corporation, Aquila Southwest Pipeline Corporation, and Koch Oil Company were \$13.5 million (19.5%), \$8.1 million (11.7%), and \$7.1 million (10.3%), respectively. In 1996, oil and gas sales to TECO Gas Marketing Company were \$6.9 million (13.0%).

**Fair Value of Financial Instruments.** The Company's financial instruments consist of cash and cash equivalents, accounts receivable, accounts payable, bank borrowings, and convertible notes. The carrying amounts of cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the highly liquid nature of these short-term instruments. The fair values of the bank borrowings approximate the carrying amounts as of December 31, 1998 and 1997 and were determined based upon interest rates currently available to the Company for borrowings with similar terms. The fair values of the convertible notes were \$81.4 million and \$113.6 million at December 31, 1998 and 1997, respectively, and were based on quoted markets prices as of the respective dates.

**New Accounting Pronouncements.** In the first quarter of 1998, the Company adopted the Statement of Financial Accounting Standards ("SFAS") No. 130, "Reporting Comprehensive Income," which requires the display of comprehensive income and its components in the financial statements. Comprehensive income represents all changes in equity during the reporting period, including net income and charges directly to equity, which are excluded from net income. The adoption of this statement does not have a material impact on the Company or its financial disclosures, as the Company has not historically and currently does not enter into transactions that result in charges (or credits) directly to equity (such as additional minimum pension liability changes, currency translation adjustments, and unrealized gains and losses on available-for-sale securities).

In June 1998, the Financial Accounting Standards Board issued SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." The Statement establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows the gains and losses on derivatives to offset related results on the hedged item in the income statements and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. SFAS No. 133 is effective for fiscal years beginning after June 15, 1999. The Company is currently evaluating the new standard, but has not yet determined the impact it will have on its financial position and results of operations.

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## 2. Earnings Per Share

Basic earnings per share ("Basic EPS") has been computed using the weighted average number of common shares outstanding during the respective periods. Basic EPS has been retroactively restated in all periods presented to give recognition to the 10% stock dividend declared in

October 1997 that resulted in an additional 1,494,622 shares being issued.

The calculation of diluted earnings per share ("Diluted EPS") assumes conversion of the Company's Convertible Notes as of the beginning of the respective periods and the elimination of the related after-tax interest expense and assumes, as of the beginning of the period, exercise of stock options and warrants (using the treasury stock method). Certain of the Company's stock options that would potentially dilute Basic EPS in the future were not included

in the computation of Diluted EPS because to do so would have been antidilutive for the 1998 period. Diluted EPS has also been retroactively restated for all periods presented to give effect to the 10% stock dividend. The original conversion price of the Convertible Notes of \$34.6875 was revised to \$31.534 to reflect the October 1997 stock dividend declared.

The following is a reconciliation of the numerators and denominators used in the calculation of Basic and Diluted EPS for the years ended December 31, 1998, 1997, and 1996:

|   | 1998           |            |                  | 1997         |            |                  | 1996         |            |                  |
|---|----------------|------------|------------------|--------------|------------|------------------|--------------|------------|------------------|
|   | Net Loss       | Shares     | Per Share Amount | Net Income   | Shares     | Per Share Amount | Net Income   | Shares     | Per Share Amount |
| Basic EPS:                                      |                |            |                  |              |            |                  |              |            |                  |
| Net Income (Loss) and Share Amounts             | \$(48,225,204) | 16,436,972 | \$ (2.93)        | \$22,310,189 | 16,492,856 | \$ 1.35          | \$19,025,450 | 15,000,901 | \$ 1.27          |
| Dilutive Securities:                            |                |            |                  |              |            |                  |              |            |                  |
| 6.25% Convertible Notes                         | —              | —          |                  | 3,525,808    | 3,646,847  |                  | 788,710      | 419,637    |                  |
| Stock Options                                   | —              | —          |                  | —            | 428,036    |                  | —            | 407,108    |                  |
| Diluted EPS:                                    |                |            |                  |              |            |                  |              |            |                  |
| Net Income (Loss) and Assumed Share Conversions | \$(48,225,204) | 16,436,972 | \$ (2.93)        | \$25,835,997 | 20,567,739 | \$ 1.26          | \$19,814,160 | 15,827,646 | \$ 1.25          |

### 3. Provision for Income Taxes

The following is an analysis of the consolidated income tax provision (benefit):

|                    | Year Ended December 31, |                     |                     |
|--------------------|-------------------------|---------------------|---------------------|
|                    | 1998                    | 1997                | 1996                |
| Current . . . . .  | \$ 214,169              | \$ 77,402           | \$ 759,253          |
| Deferred . . . . . | (25,380,546)            | 10,742,015          | 9,001,080           |
| Total . . . . .    | <u>\$(25,166,377)</u>   | <u>\$10,819,417</u> | <u>\$ 9,760,333</u> |

There are differences between income taxes computed using the statutory rate (34% for 1998, 1997, and 1996) and the Company's effective income tax rates (34.3%, 32.7%, and 33.9% for 1998, 1997, and 1996, respectively), primarily as the result of certain tax credits available to the Company. Reconciliations of income taxes computed using the statutory rate to the effective income tax rates are as follows:

|   | 1998                  | 1997                | 1996                |
|---|-----------------------|---------------------|---------------------|
| Income taxes computed at federal statutory rate | \$(24,953,138)        | \$11,264,066        | \$ 9,787,166        |
| State tax provisions, net of federal benefits   | 23,949                | 48,058              | 75,936              |
| Nonconventional fuel source credit              | (287,000)             | (294,000)           | (306,000)           |
| Depletion deductions in excess of basis         | (42,500)              | (51,000)            | (26,520)            |
| Other, net                                      | 92,312                | (147,707)           | 229,751             |
| Provision (benefit) for income taxes            | <u>\$(25,166,377)</u> | <u>\$10,819,417</u> | <u>\$ 9,760,333</u> |

The tax effects of significant temporary differences representing the net deferred tax liability (asset) at December 31, 1998 and 1997, were as follows:

|                                    | 1998                  | 1997                  |
|------------------------------------|-----------------------|-----------------------|
| Deferred tax assets:               |                       |                       |
| Alternative minimum tax credits    | \$ (1,979,399)        | \$ (1,831,299)        |
| Other                              | (237,587)             | (237,587)             |
| Total deferred tax assets          | <u>\$ (2,216,986)</u> | <u>\$ (2,068,886)</u> |
| Deferred tax liabilities:          |                       |                       |
| Oil and gas properties             | \$ 1,531,651          | \$26,785,212          |
| Other                              | 430,351               | 637,824               |
| Total deferred tax liabilities     | <u>\$ 1,962,002</u>   | <u>\$27,423,036</u>   |
| Net deferred tax liability (asset) | <u>\$ (254,984)</u>   | <u>\$25,354,150</u>   |

The Company did not record any valuation allowances against deferred tax assets at December 31, 1998 or 1997.

At December 31, 1998, the Company had alternative minimum tax credits of \$1,979,399 that carry forward indefinitely and are available to reduce future regular tax liability to the extent they exceed the related tentative minimum tax otherwise due.

#### 4. Long-Term Debt

**Convertible Notes.** The Company's convertible notes at December 31, 1998 and 1997, consist of \$115,000,000 of 6.25% Convertible Subordinated Notes due 2006. The Notes were issued on November 25, 1996, and will mature on November 15, 2006. The Notes are convertible into common stock of the Company at the option of the holders at any time prior to maturity at an adjusted conversion price of \$31.534 per share, subject to adjustment upon the occurrence of certain events. The original conversion price of \$34.6875 was adjusted downward to reflect the October 1997 10% stock dividend. Interest on the Notes is payable semiannually on May 15 and November 15, and commenced with the first payment on May 15, 1997. On or after November 15, 1999, the Notes are redeemable for cash at the option of the Company, with certain restrictions, at 104.375% of principal, declining to 100.625% in 2005. Upon certain changes in control of the Company, if the price of the Company's common stock is not above certain levels, each holder of Notes will have the right to require the Company to repurchase the Notes at the principal amount thereof, together with accrued and unpaid interest to the date of repurchase, but after the repayment of any Senior Indebtedness, as defined.

Interest expense on the Notes, including amortization of debt issuance costs, totaled \$7,544,650 and \$7,514,967 in 1998 and 1997, respectively.

**Bank Borrowings.** In August 1998, the Company closed its new \$250.0 million revolving credit facility with a syndicate of ten banks (the "New Credit Facility"). At December 31, 1998, the Company had outstanding borrowings of \$146.2 million under its New Credit Facility. At December 31, 1997, the Company had outstanding borrowings of \$7.9 million under its borrowing arrangements. At December 31, 1998, the New Credit Facility consisted of a \$250.0 million revolving line of credit with a \$170.0 million borrowing base. The interest rate is either (a) the lead bank's prime rate (7.75% at December 31, 1998) or (b) the adjusted London Interbank Offered Rate ("LIBOR") plus the applicable margin depending on the level of outstanding debt (a weighted average of 6.34% at December 31, 1998). The applicable margin is based on the Company's ratio of outstanding balance on the New Credit Facility to the last

calculated borrowing base. Of the \$146.2 million borrowed at December 31, 1998, \$145.0 million was borrowed at the LIBOR rate.

The terms of the New Credit Facility include, among other restrictions, a limitation on the level of cash dividends (not to exceed \$2.0 million in any fiscal year), requirements as to maintenance of certain minimum financial ratios (principally pertaining to working capital, debt, and equity ratios), and limitations on incurring other debt. Since inception, no cash dividends have been declared on the Company's common stock. The Company is currently in compliance with the provisions of this agreement, as amended in mid-March 1999 to modify the cash flow-to-debt covenant. The New Credit Facility will extend until August 2002.

Previously, the Company's credit facilities consisted of a \$100.0 million revolving line of credit with an \$80.0 million borrowing base and a \$7.0 million revolving line of credit with a \$5.1 million borrowing base. These facilities were with a two-bank group. Depending on the level of outstanding debt, the interest rate on the \$100.0 million revolving line of credit was (a) either the bank's base rate or the bank's base rate plus 0.25% or (b) the LIBOR rate plus 1% to 1.5%. The interest rate on the \$7.0 million revolving line of credit was the bank's base rate less 0.25%.

In addition to interest on these credit facilities, the Company pays a commitment fee to compensate the banks for making funds available. The fee on the revolving line of credit is calculated on the average daily remainder, if any, of the commitment amount less the aggregate principal amounts outstanding, plus the amount of all letters of credit outstanding during the period. The aggregate amounts of commitment fees paid by the Company were \$114,000 in 1998 and \$31,000 in 1997.

#### 5. Commitments and Contingencies

Total rental and lease expenses were \$1,117,351 in 1998, \$1,039,210 in 1997, and \$957,797 in 1996. The Company's remaining minimum annual obligations under non-cancelable operating lease commitments are \$1,146,229 for 1999, \$1,151,249 for 2000, \$1,151,249 for 2001, \$1,273,007 for 2002, and \$1,358,238 for 2003.

As of December 31, 1998, the Company is the managing general partner of 80 limited partnerships. Because the Company serves as the general partner of these entities, under state partnership law it is contingently liable for the liabilities of these partnerships, which liabilities are not material for any of the periods presented in relation to the partnerships' respective assets.

In the ordinary course of business, the Company has been party to various legal actions, which arise primarily from its activities as operator of oil and gas wells. In

management's opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on the financial position or results of operations of the Company.

## 6. Stockholders' Equity

**Common Stock.** In October 1997, the Company declared a 10% stock dividend to stockholders of record. The transaction was valued based on the closing price (\$28.8125) of the Company's common stock on the New York Stock Exchange on October 1, 1997. As a result of the issuance of 1,494,622 shares of the Company's common stock as a dividend, retained earnings were reduced by \$43,063,796, with the common stock and additional paid-in capital accounts increased by the same amount. Basic and Diluted EPS were restated for all periods presented to reflect the effect of the stock dividend.

**Stock-Based Compensation Plans.** The Company has two stock option plans, the 1990 stock compensation plan and the 1990 non-qualified plan, as well as an employee stock purchase plan.

Under the 1990 stock compensation plan, incentive stock options and other options and awards may be granted to employees to purchase shares of common stock. Under the 1990 non-qualified plan, non-employee members of the Company's Board of Directors may be granted options to purchase shares of common stock. Both plans provide that the exercise prices equal 100% of the fair value of the common stock on the date of grant. Options become exercisable for 20% of the shares on the first anniversary of the grant of the option and are exercisable for an additional 20% per year thereafter. Options granted expire 10 years after the date of grant or earlier in the event of the optionee's separation from employment. At the time the stock options are exercised, the option price is credited to common stock and additional paid-in capital.

On December 9, 1998, the Company canceled certain previously issued options under the 1990 stock compensation plan and reissued them at an option price that reflected current market value of the Company's common stock as of that date. No compensation expense was recognized in 1998 as a result of this transaction.

The employee stock purchase plan provides eligible employees the opportunity to acquire shares of Company common stock at a discount through payroll deductions. The plan year is from June 1 to the following May 31. The first year of the plan commenced June 1, 1993. To date, employees have been allowed to authorize payroll deductions of up to 10% of their base salary during the plan year by making an election to participate prior to the start of a plan year. The purchase price for stock acquired under the plan will be 85% of the lower of the closing price of the Company's common stock as quoted on the New York Stock Exchange at the beginning or end of the plan year or a date during the year chosen by the participant. Under this plan, the Company issued 20,756 shares at a price range of \$13.65 to \$18.06 in 1998, 26,551 shares at a price of \$15.19 in 1997, and 36,387 shares at a price range of \$6.59 to \$7.97 in 1996. The estimated weighted average fair value of shares issued under this plan was \$6.86 in 1998, \$4.39 in 1997, and \$2.13 in 1996. As of December 31, 1998, there remained 437,448 shares available for issuance under this plan. There are no charges or credits to income in connection with this plan.

The Company accounts for the two stock option plans under Accounting Principles Board Opinion No. 25, under which no compensation expense has been recognized. Had compensation expense for these plans been determined consistent with SFAS No. 123, "Accounting for Stock-Based Compensation," the Company's net income (loss) and earnings per share would have been reduced to the following pro forma amounts (1996 amounts have been restated to reflect the October 1997 10% stock dividend):

|                    |             | 1998           | 1997         | 1996         |
|--------------------|-------------|----------------|--------------|--------------|
| Net Income (Loss): | As Reported | \$(48,225,204) | \$22,310,189 | \$19,025,450 |
|                    | Pro Forma   | \$(49,985,171) | \$21,362,722 | \$18,750,064 |
| Basic EPS:         | As Reported | \$(2.93)       | \$1.35       | \$1.27       |
|                    | Pro Forma   | \$(3.04)       | \$1.30       | \$1.25       |
| Diluted EPS:       | As Reported | \$(2.93)       | \$1.26       | \$1.25       |
|                    | Pro Forma   | \$(3.04)       | \$1.21       | \$1.23       |

Because the SFAS No. 123 method of accounting has not been applied to options granted prior to January 1, 1995, the resulting pro forma compensation cost may not be representative of the cost to be expected in future years.

The following is a summary of the Company's stock options under these plans as of December 31, 1998, 1997, and 1996:

|  | 1998             |                       | 1997             |                       | 1996             |                       |
|--|------------------|-----------------------|------------------|-----------------------|------------------|-----------------------|
|  | Shares           | Wtd. Avg. Exer. Price | Shares           | Wtd. Avg. Exer. Price | Shares           | Wtd. Avg. Exer. Price |
| Options outstanding, beginning of period   | 1,761,512        | \$ 14.71              | 1,399,769        | \$ 12.09              | 1,308,391        | \$ 8.83               |
| Options granted  | 1,319,881        | \$ 9.72               | 401,390          | \$ 26.23              | 302,281          | \$ 23.78              |
| Options cancelled  | (730,490)        | \$ 24.15              | (31,404)         | \$ 12.99              | (11,251)         | \$ 8.81               |
| Options exercised  | (84,757)         | \$ 7.54               | (137,155)        | \$ 8.54               | (199,652)        | \$ 8.65               |
| Options adjusted for 10% stock dividend  | —                |                       | 128,912          |                       | —                |                       |
| Options outstanding, end of period   | <u>2,266,146</u> | \$ 9.03               | <u>1,761,512</u> | \$ 14.71              | <u>1,399,769</u> | \$ 12.09              |
| Options exercisable, end of period   | <u>888,695</u>   | \$ 8.64               | <u>869,484</u>   | \$ 9.05               | <u>700,271</u>   | \$ 8.82               |
| Options available for future grant, end of period                                  | <u>915,236</u>   |                       | <u>1,501,622</u> |                       | <u>38,546</u>    |                       |
| Estimated weighted average fair value per share of options granted during the year | <u>\$3.82</u>    |                       | <u>\$13.98</u>   |                       | <u>\$15.17</u>   |                       |

The fair value of each option grant, as opposed to its exercise price, is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted average assumptions in 1998, 1997, and 1996, respectively: no dividend yield, expected volatility factors of 42.3%, 38.7%, and 40.4%, risk-free interest rates of 4.69%, 6.02%, and 6.42%, and expected lives of 7.0, 7.5, and 10.0 years. The following table summarizes information about stock options outstanding at December 31, 1998:

| Range of Exercise Prices | Options Outstanding            |                                      |                          | Options Exercisable            |                          |
|--------------------------|--------------------------------|--------------------------------------|--------------------------|--------------------------------|--------------------------|
|                          | Number Outstanding at 12/31/98 | Wtd. Avg. Remaining Contractual Life | Wtd. Avg. Exercise Price | Number Exercisable at 12/31/98 | Wtd. Avg. Exercise Price |
| \$ 4.00 to \$ 8.99       | 1,147,917                      | 6.3                                  | \$ 7.87                  | 598,490                        | \$ 7.75                  |
| \$ 9.00 to \$17.99       | 1,057,251                      | 7.5                                  | \$ 9.57                  | 279,687                        | \$ 9.96                  |
| \$18.00 to \$27.00       | 60,978                         | 8.3                                  | \$ 21.47                 | 10,518                         | \$ 23.72                 |
| \$ 4.00 to \$27.00       | <u>2,266,146</u>               | 7.0                                  | \$ 9.03                  | <u>888,695</u>                 | \$ 8.64                  |

**Employee Stock Ownership Plan.** In 1996, the Company established an Employee Stock Ownership Plan ("ESOP") effective January 1, 1996. All employees over the age of 21 with one year of service are participants. The Plan has a five-year cliff vesting, and service is recognized after the Plan effective date. The ESOP is designed to enable employees of the Company to accumulate stock ownership. While there will be no employee contributions, participants will receive an allocation of stock that has been contributed by the Company. Compensation expense is reported when such shares are released to employees. The Plan may also acquire common stock of the Company purchased at fair market value. The ESOP can borrow money from the Company to buy Company stock. This was done in September 1996 to purchase 25,000 shares (adjusted to 27,500 shares after the October 1, 1997, 10% stock dividend) from the Company's chairman. Benefits will be paid in a lump sum or installments, and the participants generally have the choice of receiving cash or stock. At December 31, 1998, all of the ESOP compensation was earned. At December 31, 1997 and 1996, the unearned portions of the ESOP, \$150,055 and \$521,354, respectively, were recorded as a contra-equity account entitled "Unearned ESOP Compensation."

**Common Stock Repurchase Program.** In March 1997, the Company's Board of Directors approved a common stock repurchase program for up to \$20.0 million of the Company's common stock and subsequently extended this program through June 30, 1998. Under this program, the Company used approximately \$9.3 million of working capital to acquire 435,274 shares in the open market at an average cost of \$21.47 per share. On July 23, 1998, the Board of Directors approved a new repurchase program for up to \$10.0 million of the Company's common stock through the end of 1998. Subsequently, the Company used approximately \$2.5 million of working capital to acquire another 246,001 shares for an average cost of \$10.14 per share. Through December 31, 1998, 681,275 shares have been acquired at a total cost of \$11,841,884 and are included in "Treasury stock held, at cost" on the balance sheet.

**Shareholder Rights Plan.** In August 1997, the Board of Directors declared a dividend of one preferred share purchase right on each outstanding share of the Company's common stock. The rights are not currently exercisable but would become exercisable if certain events occurred relating to any person or group acquiring or attempting to acquire 15% or more of the Company's outstanding shares of common stock. Thereafter, upon certain triggers, each right not owned by an acquirer allows its holder to purchase Company securities with a market value of two times the \$150 exercise price.

## 7. Related-Party Transactions

The Company is the operator of a substantial number of properties owned by its affiliated limited partnerships and joint ventures and accordingly, charges these entities and third-party joint interest owners operating fees. The Company is also reimbursed for direct, administrative, and overhead costs incurred in conducting the business of the limited partnerships, which totaled approximately \$5,000,000, \$6,300,000, and \$6,100,000 in 1998, 1997, and 1996, respectively. The Company was also reimbursed by the limited partnerships and joint ventures for costs incurred in the screening, evaluation, and acquisition of producing oil and gas properties on their behalf. Such costs totaled approximately \$490,000 and \$250,000 in 1997 and 1996, respectively. The Company, with the acquisitions made in 1997, has fulfilled its responsibility of acquiring properties for such partnerships, as those partnerships are fully invested in properties. In the case where the limited partners voted to sell their remaining properties and liquidate their limited partnerships, the Company was also reimbursed for direct, administrative, and overhead costs incurred in the disposition of such properties, which costs totaled approximately \$580,000, \$675,000, and \$805,000 in 1998, 1997, and 1996, respectively.

The ESOP can borrow money from the Company to buy Company stock. This was done in September 1996 to purchase 25,000 shares (adjusted to 27,500 shares after the October 1, 1997 10% stock dividend) from the Company's chairman. Benefits will be paid in a lump sum or installments, and the participants generally have the choice of receiving cash or stock.

## 8. Foreign Activities

*New Zealand.* Since October 1995, the Company has been issued two Petroleum Exploration Permits by the New Zealand Minister of Energy. The first permit covered approximately 65,000 acres in the Onshore Taranaki Basin of New Zealand's North Island, and the second covered approximately 69,300 adjacent acres. A wholly owned subsidiary, Swift Energy New Zealand Limited, formed in late 1997, conducts the Company's New Zealand activities and owns the interest in the permits. In March 1998, the Company surrendered approximately 46,400 acres covered in the first permit, and the remaining acreage has been included as an extension of the area covered in the second permit. Under the terms of the expanded permit, the Company is obligated to drill one exploratory well prior to August 12, 1999. All other obligations under the permit have been fulfilled, including the reinterpretation of existing seismic data and the acquisition and processing of new seismic data.

On October 23, 1998, the Company entered into separate agreements with Marabella Enterprises Ltd. ("Marabella"), a subsidiary of Bligh Oil & Minerals N.L., an Australian company, to obtain from Marabella a 25% working interest in another New Zealand Petroleum Exploration Permit and for Marabella to become a 5% participant in the Company's permit. An exploration well on the Marabella permit commenced drilling on October 16, 1998, the results of which were unsuccessful. Accordingly, the \$0.4 million costs of such well were charged against earnings. The Company has also agreed in principle to participate with Marabella in an additional permit as a 17.5% working interest owner.

At December 31, 1998, the Company's investment in New Zealand was approximately \$5.0 million and is included in the unproved properties portion of oil and gas properties. Approximately \$0.4 million of such costs have been impaired.

*Russia.* On September 3, 1993, the Company signed a Participation Agreement with Senega, a Russian Federation joint stock company (in which the Company has an indirect interest of less than 1%), to assist in the development and production of reserves from two fields in Western Siberia, providing the Company with a minimum 5% net profits interest from the sale of hydrocarbon products from the fields for providing managerial, technical, and financial support to Senega. Additionally, the Company purchased a 1% net profits interest from Senega for \$0.3 million.

On December 10, 1997, the Company amended and restated the Participation Agreement. Under the amended and restated Participation Agreement, the Company retains its 6% net profits interest in the Samburg Field and agreed to assist Senega in obtaining investments necessary to develop the field. Senega is charged with the management and control of the field development. The Company's investment in Russia, prior to its impairment in the third quarter of 1998, was approximately \$10.8 million and was previously included in the unproved properties portion of oil and gas properties. However, the economic and political uncertainty and currency concerns that arose during the third quarter of 1998 in Russia, combined with the price volatility and severe tightening of international capital markets, caused the Company to re-evaluate the timing of the recovery of its capitalized costs in that country. See Note 1 to the Company's financial statements for a more detailed discussion of the impairment. Subsequent to such impairment, any costs incurred in Russia have been reported as a charge to earnings.

*Venezuela.* The Company formed a wholly owned subsidiary, Swift Energy de Venezuela, C. A., for the purpose of submitting a bid on August 5, 1993, under the Venezuelan Marginal Oil Field Reactivation Program. Although the Company did not win the bid, it has continued to gather information relating to reserves and geological and geophysical data in Venezuela, and continued to pursue cooperative ventures involving other fields and opportunities in Venezuela. The Company evaluated a number of blocks being offered by Petroleos de Venezuela, S. A. under the Third Operating Agreement Round in 1997, but decided against submitting any bid on these blocks. The Company has entered into an agreement with Tecniconsult, S. A., and Corporation EDC, S.A.C.A., Venezuelan companies, to jointly formulate and submit a proposal to Petroleos de Venezuela, S. A. for the construction and operation of a methane pipeline. Currently, the technical and economic feasibility of the project is under study. The Company's investment in Venezuela, prior to its impairment in the third quarter of 1998, was approximately \$2.8 million and was previously included in

the unproved properties portion of oil and gas properties. However, the economic uncertainty and currency concerns in Venezuela, combined with the price volatility and severe tightening of international capital markets, caused the Company to re-evaluate its prospects of participating in further Venezuelan exploration activities in the near-term and the prospects for recovery of its capitalized costs in that country. See Note 1 to the Company's financial statements for a more detailed discussion of the impairment. Subsequent to such impairment, any costs incurred in Venezuela have been reported as a charge to earnings.

## 9. Acquisition of Properties

In the third quarter of 1998, the Company purchased from Sonat Exploration Company ("Sonat"), a subsidiary of Sonat Inc., the Toledo Bend Properties located in Texas and Louisiana in the vicinity of Toledo Bend Lake for approximately \$87.0 million in cash, with approximately \$56.8 million of the total spent for producing properties, approximately \$15.0 million to purchase an interest in two gas processing plants, and approximately \$15.2 million to acquire leasehold properties. Post-closing purchase price adjustments are still being determined, but management does not expect that these adjustments will be material to the Company's financial statements.

As of December 31, 1998, estimated proved reserves for the Toledo Bend Properties were 130.5 Bcfe, of which approximately 58% was natural gas, and 59% was proved undeveloped. At such date the properties include 162 producing oil and natural gas wells in the Brookeland Field in Southeast Texas and the Masters Creek Field in Western Louisiana, 23 saltwater disposal wells, a 20% interest in two natural gas plants, associated production facilities, working interests in approximately 200,875 gross undeveloped (125,378 net undeveloped) acres, and approximately 114,000 undeveloped fee mineral acres. The Company has become operator of 115 of the 162 wells. The two gas plants are operated by a third party and have combined capacity of 250 MMcfe per day.

The Toledo Bend Properties extend one of the Company's core areas by adding producing reserves that the Company believes will significantly increase its production on a short-term basis. The Company's production on these properties amounted to approximately 11.6 Bcfe, of which 44% was natural gas. Furthermore, as a result of the Company's extensive experience in other parts of the Austin Chalk trend, the Company believes that it can successfully exploit incremental drilling opportunities in the future.

This acquisition was accounted for by the purchase method and was incorporated into the Company's results of operations in the third quarter of 1998. The following unaudited pro forma supplemental information presents consolidated results of operations as if this acquisition had occurred on January 1, 1997:

|                                       | Year Ended<br>December 31, |           |
|---------------------------------------|----------------------------|-----------|
|                                       | 1998                       | 1997      |
| (Thousands, except per share amounts) | (Unaudited)                |           |
| Revenue                               | \$115,394                  | \$139,584 |
| Net Income Before                     |                            |           |
| Non-Cash Charge                       | \$ 19,098                  | \$ 38,528 |
| Net Income (Loss)                     | \$ (40,812)                | \$ 38,528 |
| Net Income (Loss) Per Share Amounts—  |                            |           |
| Basic                                 | \$ (2.48)                  | \$ 2.34   |
| Diluted                               | \$ (2.48)                  | \$ 2.04   |

## Supplemental Information (Unaudited)

### Swift Energy Company and Subsidiaries

**Capitalized Costs.** The following table presents the Company's aggregate capitalized costs relating to oil and gas producing activities and the related depreciation, depletion, and amortization:

|   | Year Ended December 31, |                       |
|---|-------------------------|-----------------------|
|   | 1998                    | 1997                  |
| Oil and Gas Properties:                               |                         |                       |
| Proved  | \$ 497,296,068          | \$ 326,836,431        |
| Unproved (not being amortized)—Domestic               | 51,040,378              | 26,735,460            |
| Unproved (not being amortized)—Foreign                | 5,001,508               | 15,104,349            |
|   | 553,337,954             | 368,676,240           |
| Accumulated Depreciation, Depletion, and Amortization | (196,626,243)           | (67,363,393)          |
|   | <u>\$ 356,711,711</u>   | <u>\$ 301,312,847</u> |

Of the \$51,040,378 of domestic unproved property costs (primarily seismic and lease acquisition costs) at December 31, 1998, excluded from the amortizable base, \$33,360,518 was incurred in 1998, \$11,966,626 was incurred in 1997, \$3,260,112 was incurred in 1996, and \$2,953,122 was incurred in prior years. When the Company is in an active drilling mode, it has evaluated the majority of these unproved costs within a two to three year time frame. In response to current market conditions, the Company has decreased its planned 1999 drilling expenditures when compared to recent years, which when coupled with the \$15.2 million of leasehold properties acquired in the Toledo Bend Properties acquisition may extend the evaluation timeframe of such costs.

Of the \$5,001,508 of net foreign unproved property costs at December 31, 1998, being excluded from the amortizable base, \$2,521,761 was incurred in 1998, \$1,731,561 was incurred in 1997, \$545,980 was incurred in 1996, and \$202,206 was incurred in 1995. All of these costs are costs incurred in New Zealand, as the costs incurred in Russia and Venezuela were impaired in the third quarter of 1998 (see Note 1 to the Company's financial statements). The Company expects it will complete its evaluation of the New Zealand properties as wells are drilled over the next two to three years.

**Capital Expenditures.** The following table sets forth capital expenditures related to the Company's oil and gas operations:

|  | Year Ended December 31, |                       |                      |
|--|-------------------------|-----------------------|----------------------|
|  | 1998                    | 1997                  | 1996                 |
| Acquisition of proved properties                             | \$ 59,487,524           | \$ 8,417,318          | \$ 1,529,611         |
| Lease acquisitions <sup>1,2</sup>                            | 38,658,047              | 21,603,732            | 16,426,327           |
| Exploration  | 12,578,124              | 10,705,115            | 2,704,281            |
| Development  | 54,821,131              | 82,885,549            | 69,067,024           |
| Total acquisition, exploration, and development <sup>3</sup> | <u>\$ 165,544,826</u>   | <u>\$ 123,611,714</u> | <u>\$ 89,727,243</u> |
| Processing plants  | \$ 15,000,000           | \$ —                  | \$ —                 |
| Field compression facilities                                 | 2,228,101               | 7,444,070             | —                    |
| Total plants and facilities                                  | <u>\$ 17,228,101</u>    | <u>\$ 7,444,070</u>   | <u>\$ —</u>          |
| Total capital expenditures                                   | <u>\$ 182,772,927</u>   | <u>\$ 131,055,784</u> | <u>\$ 89,727,243</u> |

<sup>1</sup>Lease acquisitions for 1998, 1997, and 1996 include expenditures of: \$2,521,761, \$1,731,561, and \$545,980, respectively, relating to the Company's initiatives in New Zealand; \$421,602, \$828,133, and \$487,597, respectively, relating to initiatives in Venezuela; and \$592,841, \$658,145, and \$2,712,278, respectively, relating to initiatives in Russia.

<sup>2</sup>These are actual amounts as incurred by year, including both proved and unproved lease costs. The annual lease acquisition amounts added to proved oil and gas properties (being amortized) for 1998, 1997, and 1996, were \$13,853,129, \$7,384,385, and \$9,458,016, respectively.

<sup>3</sup>Includes capitalized general and administrative costs directly associated with the acquisition, exploration, and development efforts of approximately \$12,300,000, \$11,700,000, and \$7,400,000 in 1998, 1997, and 1996, respectively. In addition, total includes \$3,849,665, \$2,326,691, and \$1,549,575 in 1998, 1997, and 1996, respectively, of capitalized interest on unproved properties.

**Results of Operations.** The following table sets forth results of the Company's oil and gas operations:

|  | Year Ended December 31, |                      |                      |
|--|-------------------------|----------------------|----------------------|
|  | 1998                    | 1997                 | 1996                 |
| Oil and gas sales  | \$ 80,067,837           | \$ 69,015,189        | \$ 52,770,672        |
| Oil and gas production costs   | (13,138,980)            | (8,778,876)          | (6,141,941)          |
| Depreciation, depletion, and amortization                            | (38,069,355)            | (23,443,273)         | (15,812,134)         |
| Write-down of oil and gas properties                                 | (90,772,628)            | —                    | —                    |
|  | (61,913,126)            | 36,793,040           | 30,816,597           |
| Provision (benefit) for income taxes                                 | (21,236,202)            | 12,015,816           | 10,448,917           |
| Results of producing activities                                      | <u>\$ (40,676,924)</u>  | <u>\$ 24,777,224</u> | <u>\$ 20,367,680</u> |
| Amortization per physical unit of production (equivalent Mcf of gas) | <u>\$ 0.98</u>          | <u>\$ 0.92</u>       | <u>\$ 0.81</u>       |

**Supplemental Reserve Information.** The following information presents estimates of the Company's proved oil and gas reserves, which are all located onshore in the United States. All of the Company's reserves were determined by the Company and audited by H. J. Gruy and Associates, Inc. ("Gruy"), independent petroleum consultants. Gruy's summary report dated January 27, 1999, is set forth as an exhibit to the Form 10-K Report for the year ended December 31, 1998, and includes definitions and assumptions that served as the basis for the estimates of proved reserves and future net cash flows. Such definitions and assumptions should be referred to in connection with the following information:

*Estimates of Proved Reserves*

|  | Natural Gas<br>(Mcf) | Oil and<br>Condensate<br>(Bbls) |
|--|----------------------|---------------------------------|
| Proved reserves as of December 31, 1995 <sup>1</sup> | 143,567,520          | 5,421,981                       |
| Revisions of previous estimates <sup>2</sup>         | (9,544,391)          | (816,065)                       |
| Purchases of minerals in place                       | 2,676,393            | 97,178                          |
| Sales of minerals in place                           | (4,163,770)          | (340,706)                       |
| Extensions, discoveries, and other additions         | 107,762,886          | 1,745,307                       |
| Production <sup>3</sup>                              | (14,540,437)         | (623,386)                       |
| Proved reserves as of December 31, 1996 <sup>1</sup> | 225,758,201          | 5,484,309                       |
| Revisions of previous estimates <sup>2</sup>         | (22,774,899)         | (427,412)                       |
| Purchases of minerals in place                       | 30,342,398           | 580,278                         |
| Sales of minerals in place                           | (1,155,706)          | (50,909)                        |
| Extensions, discoveries, and other additions         | 102,479,883          | 2,945,037                       |
| Production <sup>3</sup>                              | (20,344,208)         | (672,385)                       |
| Proved reserves as of December 31, 1997 <sup>1</sup> | 314,305,669          | 7,858,918                       |
| Revisions of previous estimates <sup>2</sup>         | (42,958,447)         | (2,291,223)                     |
| Purchases of minerals in place                       | 54,189,901           | 7,237,298                       |
| Sales of minerals in place                           | (1,727,878)          | (39,932)                        |
| Extensions, discoveries, and other additions         | 55,951,332           | 2,993,540                       |
| Production <sup>3</sup>                              | (27,359,742)         | (1,800,676)                     |
| Proved reserves as of December 31, 1998 <sup>1</sup> | <u>352,400,835</u>   | <u>13,957,925</u>               |
| Proved developed reserves,                           |                      |                                 |
| December 31, 1995                                    | 81,532,025           | 3,313,226                       |
| December 31, 1996                                    | 135,424,880          | 3,622,480                       |
| December 31, 1997                                    | 191,108,214          | 4,288,696                       |
| December 31, 1998                                    | 197,105,963          | 7,142,566                       |

<sup>1</sup>Proved reserves exclude quantities subject to the Company's volumetric production payment agreement.

<sup>2</sup>Revisions of previous estimates are related to upward or downward variations based on current engineering information for production rates, volumetrics, and reservoir pressure. Additionally, changes in quantity estimates are affected by the increase or decrease in crude oil and natural gas prices at each year end. Proved reserves, as of December 31, 1998, were based upon prices of \$2.23 per Mcf of natural gas and \$11.23 per barrel of oil, compared to \$2.78 per Mcf and \$15.76 per barrel as of December 31, 1997.

<sup>3</sup>Natural gas production for 1996, 1997, and 1998 excludes 1,156,361, 1,015,226, and 866,232 Mcf, respectively, delivered under the Company's volumetric production payment agreement.

**Standardized Measure of Discounted Future Net Cash Flows.** The standardized measure of discounted future net cash flows relating to proved oil and gas reserves is as follows:

|  | Year Ended December 31, |                       |                       |
|--|-------------------------|-----------------------|-----------------------|
|  | 1998                    | 1997                  | 1996                  |
| Future gross revenues  | \$ 972,852,038          | \$ 994,828,072        | \$ 1,141,831,786      |
| Future production costs  | (294,307,549)           | (273,475,056)         | (228,626,881)         |
| Future development costs   | (118,420,782)           | (92,946,811)          | (59,988,855)          |
| Future net cash flows before income taxes  | 560,123,707             | 628,406,205           | 853,216,050           |
| Future income taxes  | (123,875,660)           | (135,587,216)         | (211,375,632)         |
| Future net cash flows after income taxes   | 436,248,047             | 492,818,989           | 641,840,418           |
| Discount at 10% per annum  | (145,974,944)           | (199,980,649)         | (274,608,116)         |
| Standardized measure of discounted future net cash flows relating to proved oil and gas reserves | <u>\$ 290,273,103</u>   | <u>\$ 292,838,340</u> | <u>\$ 367,232,302</u> |

The standardized measure of discounted future net cash flows from production of proved reserves was developed as follows:

1. Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions.

2. The estimated future gross revenues of proved reserves are priced on the basis of year-end prices, except in those instances where fixed and determinable gas price escalations are covered by contracts limited to the price the Company reasonably expects to receive.

3. The future gross revenue streams are reduced by estimated future costs to develop and to produce the proved reserves, as well as certain abandonment costs based on year-end cost estimates and the estimated effect of future income taxes.

4. Future income taxes are computed by applying the statutory tax rate to future net cash flows reduced by the tax basis of the properties, the estimated permanent differences applicable to future oil and gas producing activities, and tax carry forwards.

The estimates of cash flows and reserves quantities shown above are based on year-end oil and gas prices for each period. Under Securities and Exchange Commission rules, companies that follow the full-cost accounting method are required to make quarterly Ceiling Test calculations,

using prices in effect as of the period end date presented (see Note 1). Application of these rules during periods of relatively low oil and gas prices, even if of short-term seasonal duration, may result in write-downs.

The standardized measure of discounted future net cash flows is not intended to present the fair market value of the Company's oil and gas property reserves. An estimate of fair value would also take into account, among other things, the recovery of reserves in excess of proved reserves, anticipated future changes in prices and costs, an allowance for return on investment, and the risks inherent in reserve estimates.

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

|  | Year Ended December 31, |                |                |
|--|-------------------------|----------------|----------------|
|  | 1998                    | 1997           | 1996           |
| Beginning balance  | \$ 292,838,340          | \$ 367,232,302 | \$ 128,904,084 |
| Revisions to reserves proved in prior years—   |                         |                |                |
| Net changes in prices, production costs, and future development costs                | (107,301,930)           | (237,149,170)  | 145,661,994    |
| Net changes due to revisions in quantity estimates                                   | (47,924,995)            | (27,188,512)   | (25,755,091)   |
| Accretion of discount  | 35,034,478              | 47,068,172     | 14,703,841     |
| Other  | (34,966,058)            | (37,336,420)   | 7,609,227      |
| Total revisions  | (155,158,505)           | (254,605,930)  | 142,219,971    |
| New field discoveries and extensions, net of future production and development costs | 73,956,430              | 110,396,029    | 208,250,909    |
| Purchases of minerals in place   | 87,628,829              | 29,290,334     | 6,835,362      |
| Sales of minerals in place   | (1,928,900)             | (2,373,547)    | (8,084,581)    |
| Sales of oil and gas produced, net of production costs                               | (65,680,050)            | (58,786,505)   | (44,958,559)   |
| Previously estimated development costs incurred                                      | 51,622,419              | 55,742,684     | 19,883,446     |
| Net change in income taxes   | 6,994,540               | 45,942,973     | (85,818,330)   |
| Net change in standardized measure of discounted future net cash flows               | (2,565,237)             | (74,393,962)   | 238,328,218    |
| Ending balance   | \$ 290,273,103          | \$ 292,838,340 | \$ 367,232,302 |

**Quarterly Results.** The following table presents summarized quarterly financial information for the years ended December 31, 1997 and 1998:

|                            | Revenues      | Income (Loss)<br>Before<br>Income Taxes | Net Income<br>(Loss) | Basic Earnings<br>(Loss)<br>Per Share <sup>1</sup> | Diluted Earnings<br>(Loss)<br>Per Share <sup>1</sup> |
|----------------------------|---------------|---|----------------------|--|--|
| 1997                       |               |   |                      |  |  |
| First Quarter              | \$ 19,997,502 | \$ 10,161,045                           | \$ 6,769,263         | \$ .41   | \$ .37   |
| Second Quarter             | 15,653,078    | 6,007,474                               | 4,113,689            | .25  | .24  |
| Third Quarter              | 17,895,979    | 7,024,524                               | 4,685,689            | .29  | .27  |
| Fourth Quarter             | 21,165,621    | 9,936,563                               | 6,741,548            | .41  | .37  |
| Total                      | \$ 74,712,180 | \$ 33,129,606                           | \$ 22,310,189        | \$ 1.35  | \$ 1.26  |
| 1998                       |               |   |                      |  |  |
| First Quarter              | \$ 16,475,229 | \$ 4,835,502                            | \$ 3,229,615         | \$ .20   | \$ .20   |
| Second Quarter             | 16,340,730    | 4,270,153                               | 2,896,470            | .18  | .18  |
| Third Quarter <sup>2</sup> | 24,557,553    | (87,052,299)                            | (57,431,015)         | (3.50)   | (3.50)   |
| Fourth Quarter             | 25,095,709    | 4,555,063                               | 3,079,726            | .19  | .19  |
| Total                      | \$ 82,469,221 | \$ (73,391,581)                         | \$(48,225,204)       | \$ (2.93)  | \$ (2.93)  |

<sup>1</sup>Amounts prior to the fourth quarter of 1997 have been retroactively restated to give recognition to: (a) an equivalent change in capital structure as a result of a 10% stock dividend in October 1997 (see Note 2 to the Company's financial statements); and (b) the adoption of Statement of Financial Accounting Standards No. 128, "Earnings per Share." See Note 2 to the Company's financial statements.

<sup>2</sup>The loss in the third quarter of 1998 was the result of a pre-tax write-down of oil and gas properties of \$90.8 million (\$59.9 million after tax). See Note 1 to the Company's financial statements.

## **Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure**

None.

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### **PART III**

## **Item 10. Directors and Executive Officers of the Registrant**

The information to be set forth under the captions "Election of Directors" and "Executive Officers" in the Company's definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with the May 11, 1999, annual shareholders' meeting is incorporated herein by reference.

## **Item 11. Executive Compensation**

The information appearing under the caption "Executive Compensation" in the Company's definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with the May 11, 1999, annual shareholders' meeting is incorporated herein by reference.

## **Item 12. Security Ownership of Certain Beneficial Owners and Management**

The information appearing under the caption "Principal Shareholders" in the Company's definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with the May 11, 1999, annual shareholders' meeting is incorporated herein by reference.

## **Item 13. Certain Relationships and Related Transactions**

The information appearing under the caption "Certain Relationships and Related Transactions" in the Company's definitive proxy statement to be filed within 120 days after the close of the fiscal year-end in connection with the May 11, 1999, annual shareholders' meeting is incorporated herein by reference.

## PART IV

### Item 14. Exhibits, Financial Statement Schedules and Reports on Form 8-K

(a) 1. The following consolidated financial statements of Swift Energy Company together with the report thereon of Arthur Andersen LLP dated February 10, 1999, and the data contained therein are included in Item 8 hereof:

|   |    |
|---|----|
| Report of Independent Public Accountants .....        | 21 |
| Consolidated Balance Sheets .....                     | 22 |
| Consolidated Statements of Income .....               | 23 |
| Consolidated Statements of Stockholders' Equity ..... | 24 |
| Consolidated Statements of Cash Flows .....           | 25 |
| Notes to Consolidated Financial Statements .....      | 26 |

#### 2. Financial Statement Schedules

None

#### 3. Exhibits

- 3(a).1<sup>1</sup> Articles of Incorporation, as amended through June 3, 1988.
- 3(a).2<sup>2</sup> Articles of Amendment to Articles of Incorporation filed on June 4, 1990.
- 3(b)<sup>3</sup> By-Laws, as amended through August 14, 1995.
- 4(a)<sup>8</sup> Indenture dated as of November 25, 1996, between Swift Energy Company and Bank One, Columbus, N.A. as Trustee.
- 10.1<sup>1</sup> + Indemnity Agreement dated July 8, 1988, between Swift Energy Company and A. Earl Swift (plus schedule of other persons with whom Indemnity Agreements have been entered into).
- 10.2<sup>4</sup> + Swift Energy Company 1990 Nonqualified Stock Option Plan.
- 10.3<sup>12</sup> Credit Agreement among Swift Energy Company and Bank One, Texas, National Association as administrative agent, Bank of Montreal as syndication agent, and Nationsbank, N.A. as documentation agent and the lenders signatory hereto dated August 18, 1998.
- 10.4\* First and Second Amendments to Credit Agreement among Swift Energy Company and Bank One, Texas, National Association as administrative agent, Bank of Montreal as syndication agent, and Nationsbank, N.A. as documentation agent and the lenders signatory hereto dated September 30, 1998, and December 31, 1998.
- 10.5<sup>13</sup> + Amended and Restated Swift Energy Company 1990 Stock Compensation Plan, as of May 1997.
- 10.6<sup>3</sup> + Employment Agreement dated as of November 1, 1995, by and between Swift Energy Company and Terry E. Swift.
- 10.7<sup>3</sup> + Employment Agreement dated as of November 1, 1995, by and between Swift Energy Company and John R. Alden.
- 10.8<sup>3</sup> + Employment Agreement dated as of November 1, 1995, by and between Swift Energy Company and James M. Kitterman.
- 10.9<sup>3</sup> + Employment Agreement dated as of November 1, 1995, by and between Swift Energy Company and Bruce H. Vincent.
- 10.10<sup>3</sup> + Employment Agreement dated as of November 1, 1995, by and between Swift Energy Company and A. Earl Swift.
- 10.11<sup>6</sup> + Agreement and Release between Swift Energy Company and Virgil Neil Swift effective June 1, 1994.
- 10.12<sup>7</sup> + First Amendment to Agreement and Release dated as of 12/1/95, by and between Swift Energy Company and Virgil Neil Swift.
- 10.13<sup>7</sup> + Second Amendment to Agreement and Release dated as of 2/2/96, by and between Swift Energy Company and Virgil Neil Swift, effective January 1, 1996.
- 10.14<sup>7</sup> + Second [sic] Amendment to Agreement and Release dated as of 1/14/97, by and between Swift Energy Company and Virgil Neil Swift, effective December 1, 1996.
- 10.15<sup>10</sup> Employment Agreement dated as of February 1, 1998, by and between Swift Energy Company and Joseph A. D'Amico.
- 10.16<sup>9</sup> Rights Agreement dated as of August 1, 1997, between Swift Energy Company and American Stock Transfer & Trust Company.
- 10.17<sup>11</sup> Purchase and Sale Agreement dated as of June 1, 1998, between Swift Energy Company and Sonat Inc.
- 10.18\* Amendment to Employment Agreement dated as of November 1, 1995, by and between Swift Energy Company and A. Earl Swift.
- 18<sup>5</sup> Letter from Arthur Andersen LLP dated February 17, 1995, regarding change in accounting principle.
- 21<sup>6</sup> List of Subsidiaries of Swift Energy Company.
- 23(a)\* The consent of H. J. Gruy and Associates, Inc.
- 23(b)\* The consent of Arthur Andersen LLP as to incorporation by reference regarding Form S-8 Registration Statements.
- 27 Financial Data Schedule (included in electronic filing only).
- 99\* The summary of H. J. Gruy and Associates, Inc. report, dated January 27, 1999.

(b) During the fourth quarter of 1998 the Company filed a report on Form 8-K, dated November 25, 1998, pertaining to the Company's filing of a Registration Statement on Form S-4 (Registration No. 333-50637) relating to the Company's then pending proposal to purchase substantially all of the assets of 63 partnerships of which the Company is the Managing General Partner. The Form 8-K included unaudited financial statements for the quarter ended September 30, 1998, for 24 of the 63 partnerships which are not required to file reports pursuant to Section 13 or 15(d) of the Securities and Exchange Act of 1934, as amended, so that if such financial statements were sent to investors in the partnerships in connection with proposals which were to be made to them, such financials would be publicly available.

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<sup>1</sup>Incorporated by reference from Swift Energy Company Annual Report on Form 10-K for the fiscal year ended December 31, 1988, File No. 1-8754.

<sup>2</sup>Incorporated by reference from Swift Energy Company Annual Report on Form 10-K for the fiscal year ended December 31, 1992.

<sup>3</sup>Incorporated by reference from Swift Energy Company Quarterly Report on Form 10-Q filed for the quarterly period ended September 30, 1995.

<sup>4</sup>Incorporated by reference from Registration Statement No. 33-36310 on Form S-8 filed on August 10, 1990.

<sup>5</sup>Incorporated by reference from Swift Energy Company Annual Report on Form 10-K for the fiscal year ended December 31, 1994.

<sup>6</sup>Incorporated by reference from Registration Statement No. 33-60469 on Form S-2 filed on June 22, 1995.

<sup>7</sup>Incorporated by reference from Swift Energy Company Annual Report on Form 10-K from the fiscal year ended December 31, 1996.

<sup>8</sup>Incorporated by reference from Registration Statement No. 33-14785 on Form S-3 filed on October 24, 1996.

<sup>9</sup>Incorporated by reference from Swift Energy Company Report on Form 8-K dated August 1, 1997.

<sup>10</sup>Incorporated by reference from Swift Energy Company Quarterly Report on Form 10-Q filed for the quarterly period ended June 30, 1998.

<sup>11</sup>Incorporated by reference from Swift Energy Company Report on Form 8-K dated July 2, 1998.

<sup>12</sup>Incorporated by reference from Swift Energy Company Quarterly Report on Form 10-Q filed for the quarterly period ended September 30, 1998.

<sup>13</sup>Incorporated by reference from Swift Energy Company definitive proxy statement for annual shareholders meeting filed April 14, 1997.

\* Filed herewith.

+ Management contract or compensatory plan or arrangement.



| <u>Signatures</u>                                    | <u>Title</u> | <u>Date</u>    |
|--|--------------|----------------|
| /S/ G. Robert Evans<br><hr/> G. Robert Evans         | Director     | March 24, 1999 |
| /S/ Raymond O. Loen<br><hr/> Raymond O. Loen         | Director     | March 24, 1999 |
| /S/ Henry C. Montgomery<br><hr/> Henry C. Montgomery | Director     | March 24, 1999 |
| /S/ Clyde W. Smith, Jr.<br><hr/> Clyde W. Smith, Jr. | Director     | March 24, 1999 |
| /S/ Harold J. Withrow<br><hr/> Harold J. Withrow     | Director     | March 24, 1999 |

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

EXHIBITS

TO

FORM 10-K REPORT

FOR THE

YEAR ENDED DECEMBER 31, 1998

SWIFT ENERGY COMPANY

16825 NORTHCHASE DRIVE, SUITE 400

HOUSTON, TEXAS 77060

## EXHIBITS

- 10.4 First and Second Amendments to Credit Agreement among Swift Energy Company and Bank One, Texas, National Association as administrative agent, Bank of Montreal as syndication agent, and Nationsbank, N.A. as documentation agent and the lenders signatory hereto dated September 30, 1998, and December 31, 1998.
- 10.18 Amendment to Employment Agreement dated as of November 1, 1995, by and between Swift Energy Company and A. Earl Swift.
- 23 (a) The consent of H.J. Gruy and Associates, Inc.
- 23 (b) The consent of Arthur Andersen LLP as to incorporation by reference of its report into Form S-8 Registration Statements.
- 99 The summary of H.J. Gruy and Associates, Inc. report, dated January 27, 1999.

EXHIBIT 10.4

EXHIBIT 10.18

EXHIBIT 23 (A)

EXHIBIT 23 (B)

CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS

As independent public accountants, we hereby consent to the incorporation of our report dated February 10, 1999, included in the annual report of Swift Energy Company on Form 10-K for the year ended December 31, 1998, into Swift Energy Company's previously filed Registration Statements File Numbers 33-14305, 33-36310, 33-80228, and 33-80240 on Form S-8.

ARTHUR ANDERSEN LLP

Houston, Texas  
March 24, 1999

EXHIBIT 99