CASCADE NATURAL GAS CORP
Form 10-K
December 19, 2003

FORM 10-K

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended September 30, 2003 **Commission file number: 1-7196**

CASCADE NATURAL GAS CORPORATION

(Exact name of Registrant as specified in its charter)

Washington (State or other jurisdiction of incorporation or organization)	**91-0599090** (I.R.S. Employer Identification No.)
222 Fairview Avenue North **Seattle, WA 98109** (Address of principal executive offices)	**(206) 624-3900** (Registrant s telephone number including area code)

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

Title of Each Class	**Name of Each Exchange on which Registered**
Common Stock, Par Value $1 per Share	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 (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

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. o

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2). Yes ý No o

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of the close of business on November 26, 2003, was $224,046,051

Indicate the number of shares outstanding of each of the registrant s classes of common stock, as of the latest practicable date.

Title	Outstanding
Common Stock, Par Value $1 per Share	11,166,261 as of November 26, 2003

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s definitive proxy statement for its 2004 Annual Meeting of Shareholders are incorporated by reference into Part III, Items 10, 11, 12, 13 and 14.

CASCADE NATURAL GAS CORPORATION

Annual Report to the Securities and Exchange Commission on Form 10-K

For the Fiscal Year Ended September 30, 2003

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PART I

Item 1. Business

Available Information

The Company makes available free of charge, on or through its website, http://www.cngc.com, its annual, quarterly and current reports, and any amendments to those reports, as soon as reasonably practicable after electronically filing such reports with the Securities and Exchange Commission. In addition, copies of these documents may be requested, at no cost, from the Company s corporate headquarters. Requests should be directed to Shareholder Relations, Cascade Natural Gas Corporation, 222 Fairview Avenue North, Seattle WA 98109, or by phone at 206-624-3900.

To contact any independent board member you may write to Larry L. Pinnt, Board of Directors Chair, P.O. Box 87, Redmond, WA 98073-0087, fax to 425-895-1349, or e-mail to lpinnt@cngc.com.

General

Cascade Natural Gas Corporation (Cascade or the Company) was incorporated under the laws of the state of Washington on January 2, 1953. Its principal business is the distribution of natural gas to customers in the states of Washington and Oregon. Approximately 81% of its gas distribution revenues are from customers in the state of Washington.

As of September 30, 2003, the Company had approximately 177,300 residential customers, 28,900 commercial customers, and 800 industrial and other customers. Residential, commercial, and most small industrial customers are generally core customers, who take traditional bundled natural gas service, which includes supply, peaking service, and upstream interstate pipeline transportation. Sales to core customers in fiscal 2003 accounted for approximately 21% of gas deliveries and 68% of operating margin. The Company s sales to its core residential and commercial customers are influenced by fluctuations in temperature, particularly during the winter season. A warm winter season will tend to reduce gas consumption. Over the longer term, these fluctuations tend to offset each other, as rates charged to customers are developed based on the assumption of normal weather.

Non-core customers are generally large industrial and institutional customers who have chosen unbundled service, meaning that they select from among several upstream supply, pipeline transportation, and gas management service options independent of the Company s distribution service. The Company s margin from non-core customers is derived primarily from distribution service and to a lesser extent from gas management service revenue. Gas management service revenue primarily includes fees charged to non-core customers in consideration of securing gas supplies and pipeline capacity for the customers.

State Regulation

The Company s rates and practices are regulated by the Washington Utilities and Transportation Commission (WUTC) and the Oregon Public Utility Commission (OPUC).

Cascade s gas supply contracts contain pricing provisions for fixed periods of time. To the extent that prices are changed with respect to supplies purchased for core customers, Cascade is able to pass the effect of such changes, subject to regulatory review, to its customers by means of a periodic purchased gas cost adjustment (PGA) in each state. Gas price changes occurring between times when PGA rate changes become effective are deferred for pass through in the next PGA.

With respect to such gas supplies delivered to Oregon customers, 67% of the incremental change in the actual cost of gas supplies, as compared to the forecasted cost reflected in the PGA, is deferred. The remaining 33% (increase or decrease) is absorbed by the Company. This mechanism is intended to encourage the Company to seek opportunities to lower its cost of supplies and to be innovative in its management of the supply portfolio to avoid price spikes. Cascade s gas supply portfolio for Oregon core customers is comprised mostly of gas supplies that have a fixed commodity price, therefore management believes the risk or opportunity for the Company is not significant under the 67% / 33% sharing arrangement during the coming year.

Cascade has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the Oregon Public Utilities Commission. The mechanism was designed as an incentive to pursue operational efficiencies and new revenue opportunities, and to share the success of such pursuits with ratepayers if the Company s earnings exceed a calculated ceiling. Under that arrangement, the Company is authorized to retain all of its earnings up to a threshold level equal to the average of the annual yields, reported monthly, for five-, seven-, and ten-year US Treasury debt securities for the test period plus 710 basis points. If the adjusted Oregon earnings are below the threshold, there is no rate adjustment. If the adjusted earnings are above the threshold, one-third of the earnings exceeding the threshold will be refunded to customers through future rate reductions.

The Company is also subject to state regulation with respect to integrated resource planning, and its most recent update of its Integrated Resource Plan (IRP) was filed in 2002 with both the WUTC and the OPUC. The IRP shows the Company s optimum set of supply and demand side resources that minimizes costs and risk over the twenty-year planning horizon. The IRP also sets forth possible core customer growth scenarios for a twenty-year period. In addition, the IRP sets forth the Company s demand side management goals of achieving certain conservation levels in customer usage.

The IRP also sets forth the Company s supply side management plans regarding transportation capacity and gas supply acquisition over a twenty-year period. The Company develops updates of the IRP every two years. These updated documents take into account input solicited from the public and the WUTC and OPUC staffs. While the filing of the IRP with both commissions gives the Company no advance assurance that its acquisitions of pipeline transportation capacity and gas supplies will be recognized in rates, management believes that the integrated resource planning process benefits the Company by giving it the opportunity to obtain input from regulators and the public concurrently with making these important strategic decisions. Until the Company receives final regulatory approval of these decisions in the context of the rate-making process, the Company cannot predict with certainty the extent to which the integrated resource planning process will affect its rates.

Natural Gas Supply

The majority of Cascade s supply of natural gas is transported via Williams Gas Pipelines - West (Williams). Williams owns and operates a transmission system extending from points of interconnection with El Paso Natural Gas Company and Transwestern Pipeline Company near Blanco, New Mexico through the states of New Mexico, Colorado, Utah, Wyoming, Idaho, Oregon and Washington to the Canadian border near Sumas, Washington. Natural gas is transported north from the Colorado and New Mexico area, and south from British Columbia, Canada. The Company is also a shipper on the transmission system of Gas Transmission Northwest Corporation (GTN). GTN owns and operates a gas transmission line that connects with the facilities of the TransCanada Pipeline at the international border near Kingsgate, British Columbia and extends through Washington and central Oregon into California. Cascade also receives natural gas directly from Duke Energy Gas Transmission at the Canadian border near Sumas, Washington.

Presently, baseload requirements for Cascade s core market are provided by six major gas supply contracts with various expiration dates from 2003 through 2008 and averaging 527,000 therms per day of Canadian supply and 180,000 therms per day of domestic supply. These contracts are supplemented by various service agreements to cover periods of peak demand including three storage agreements. One such agreement, with Williams, extends to October 31, 2014 and provides for 167,890 therms per day and a maximum, renewable inventory of 6,043,510 therms. The second storage agreement is with Avista Energy, and has a primary term ending April 30, 2004 and entitles Cascade to receive up to 150,000 therms per day and a maximum, renewable inventory of 4,800,000 therms. A third contract, also with Williams, for liquefied natural gas (LNG) storage is effective through October 31, 2014. Under this LNG agreement, Cascade is entitled to receive up to 600,000 therms per day to a maximum inventory of 5,622,000 therms. In addition to withdrawal and inventory capacity, Cascade maintains a corresponding amount of firm transportation from the storage facility to the city gate for each of these agreements.

During 2003, Cascade purchased approximately 92% of its gas supplies from firm gas supply contracts and 8% from 30-day spot market contracts. In addition, 543,301,000 therms of customer purchased supplies were transported through Cascade facilities.

Cascade s total cost of gas depends primarily on the prices negotiated with producers and brokers, coupled with the cost of interstate and Canadian pipeline transportation. Substantially all gas supplies for Oregon core customers and the majority of gas supplies for Washington core customers are currently purchased on contracts with supplies and prices fixed through 2004. Management believes that this, together with use of storage volumes, provides Cascade with the ability to mitigate the effects on Cascade and its customers of spikes in the market price of natural gas.

Federal Energy Regulatory Commission (FERC) Matters

Cascade is not subject to regulation by the FERC, however FERC actions can affect the amounts Cascade pays to interstate pipeline companies for interstate deliveries of natural gas supplies. Several issues are pending before FERC, or are on appeal before the U.S. Court of Appeals. The final outcome may affect prices Cascade pays. Since the policies of the WUTC and OPUC provide for 100% pass through of costs subject to FERC regulation, the Company expects that the final resolution of pending issues will not significantly affect net income.

Curtailment Procedures

In previous heating seasons, cold weather has required Cascade to significantly curtail deliveries to its interruptible customers. Cascade has not curtailed any firm customers, except under force majeure conditions. Cascade s tariffs effective in Washington and Oregon allow for curtailment of interruptible services, which are provided at rates lower than for firm services. In the event of curtailment by Cascade of firm service due to force majeure, Cascade s tariffs provide that it will not be liable for damages to any customer for failure to deliver gas curtailed in accordance with the provisions of the tariffs. The tariffs provide for appropriate adjustment of the monthly charges to firm customers curtailed by reason of an insufficient supply of gas.

Territory Served and Franchises

The population of communities served by Cascade totals approximately 1,009,000. At the end of September 2003, Cascade had the franchises necessary for the distribution of natural gas in all but two of the communities it serves in Washington and Oregon. Those franchises expired during fiscal 2003. Negotiations for those franchises are expected to be completed within fiscal year 2004. Under the laws of those states, incorporated municipalities and counties may grant non-exclusive franchises for a fixed term of years conferring upon the grantee certain rights with respect to public streets and highways in the location, construction, operation, maintenance and removal of gas distribution facilities.

In the opinion of Cascade s management, none of its franchises contain any restrictions or requirements that are of a materially burdensome nature, and such franchises are adequate for the conduct of Cascade s present business. Franchises expire on various dates from fiscal 2004 to 2065. Management has not incurred significant difficulties in renewing franchises when they expire and does not expect any significant problems in the future.

Customers

Residential and commercial customers principally use natural gas for space heating and water heating. This market is very weather-sensitive. See Seasonality below.

Agreements with Cascade s principal industrial customers are for fixed terms of not less than one year and provide for automatic extension from year to year unless terminated by either party on at least 30-days notice.

The principal industrial activities in Cascade s service area include the production of pulp, paper and converted paper products, plywood, industrial chemicals; refining of crude oil; the processing, flash freezing and canning of many types of vegetable, fruit and fish products; processing of milk products; meat processing; drying and curing of wood and agricultural products; and electric power generation. Electric generation customers represent a significant portion of industrial revenues. The demand for gas-fired generation tends to decrease as the availability of hydroelectric generation increases.

Seasonality

Weather is an important factor affecting gas revenues because of the large number of customers using gas for space heating. For the fiscal year ended September 30, 2003, 69% of operating revenues and 105% of income from operations were derived from the first two quarters (October 2002 through March 2003). Because of the seasonality of space heating revenues, financial results for interim periods are not indicative of results to be expected for an entire year. To mitigate the seasonality of space heating revenues, the Company pursues a marketing strategy of encouraging the installation of gas water heaters by customers, since they are not as influenced by weather conditions.

Competitive Conditions

Cascade operates in a competitive market for natural gas service. Cascade competes with residual fuel oil and other alternative energy sources for industrial boiler uses, and oil, propane, and electricity for residential and commercial space heating, and electricity for water heating.

Competition is primarily based on price. Though wholesale natural gas prices have increased significantly beginning in the 2000 - 2001 heating season, Cascade s residential and commercial rate schedules continue to maintain a price advantage over oil in its entire service territory and has an advantage over electricity in the vast majority of its territory. In the remaining areas of its service territory served by public electric utilities with their own hydro power supply, Cascade is almost equal in cost with respect to electricity furnished by those utilities for space heating and water heating uses. In addition, natural gas enjoys the advantage of being the preferred energy choice by builders for new home construction.

The large volume industrial market has always been very sensitive to price fluctuations between the comparable cost of natural gas and alternate fuels, principally residual fuel oil used in boiler applications. However, the advent of open access transportation in the late 1980 s and early 1990 s and the subsequent restructuring of gas supply and contractual provisions with these customers have improved the Company s competitive position. With the escalation of wholesale natural gas prices that began in the 2000 - 2001 heating season, the Company has experienced some movement of its gas load to alternative fuels and some plant curtailments by industrial customers.

In addition to multiple alternative fuels, the Company is subject to bypass. Bypass refers to actual or prospective customers who install their own facilities and connect directly to an upstream pipeline and thereby bypass the company s distribution service. The Company has in the past experienced bypass, but has also experienced success in offering competitive rates to reduce economic incentives to bypass.

The Company competes with others in acquiring gas supplies for resale to governmental and industrial customers. Further opportunities in this area will be dependent upon market conditions that can change over time, credit worthiness of customers and the increase or decrease in the number of competing providers that are available.

The Bonneville Power Administration (BPA) is a major supplier of hydroelectric power in the Pacific Northwest including Cascade s service area. BPA significantly influences the electric rates of all classes of customers including those applications in direct competition with natural gas marketed by Cascade.

Environmental

The Company is subject to federal and state environmental regulation of its operations and properties through the United States Environmental Protection Agency, the Washington Department of Ecology and the Oregon Department of Environmental Quality. Such regulation may, at times, result in the imposition of liability or responsibility for the clean up or treatment of existing environmental problems or for the prevention of future environmental problems. For detailed descriptions of specific environmental issues, see Environmental Matters under Item 7.

Capital Expenditures

Capital expenditures are primarily used to expand the Company s distribution system to serve its expanding customer base, as well as to increase deliverability on its existing system to accommodate increased customer utilization. Capital expenditures for the five fiscal years ended September 30, 2003 totaled approximately $103.3 million, and the budget for fiscal 2004 is $35.0 million.

The Company is currently forecasting that capital expenditures will total approximately $135 million over the next five years, including an estimated total of $10 to $12 million in 2004 and 2005 for a project to automate the reading of customer meters. The overall objective is to invest limited capital to generate the highest possible returns within the shortest possible time, while assuming prudent risk, anticipating customer needs and complying with the requirements of regulators.

Non-Utility Subsidiaries

Cascade has four non-utility subsidiaries, only two of which are actively engaged in business at present. Cascade Land Leasing is engaged in the servicing of loans that were made to Cascade s gas customers to finance their purchases of energy-efficient appliances. The subsidiary ceased making new loans in September 1997. Beginning in November 1998, CGC Resources began serving as an entity engaged in pipeline capacity management, with the objective of mitigating gas costs for Cascade. The subsidiaries, which in the aggregate account for less than 1% of the consolidated assets of the Company, do not currently have a significant impact on Cascade s financial statements.

Personnel

At September 30, 2003, Cascade had 437 employees. Of the total employees, 194 are represented by the International Chemical Workers Union. The present contract with the union extends to April 1, 2006, and remains in force thereafter from year to year unless terminated by either party by written notice sixty days prior to the expiration date.

Item 2. Properties

At September 30, 2003, Cascade s utility plant investments included approximately 4,917 miles of distribution mains ranging in diameter from two inches to twenty inches, 215 miles of transmission mains ranging in diameter from two inches to sixteen inches, and 3,420 miles of service lines.

The distribution and transmission mains are located under public property such as streets and highways or on private property with the permission or consent of the individual owner.

Cascade owns 21 buildings used for operations, office space and warehousing in Washington and six such buildings in Oregon. It leases five commercial offices and warehouse buildings. Cascade considers its properties well maintained and in good operating condition, and adequate for Cascade s present and anticipated needs. All facilities are substantially utilized. In addition, the Company owns two buildings currently for sale due to operational consolidation.

Item 3. Legal Proceedings

Litigation: In the fourth quarter of fiscal 2002 a fatal accident occurred involving facilities owned by the Company, located on the property of one of the Company s commercial customers. In fiscal 2003 a settlement of all plaintiffs claims was agreed to in consideration of a $750,000 payment. The Company and its co-defendant have each paid $375,000, and have agreed to resolve the allocation of the total settlement payment between them in future negotiations or proceedings.

Other: Incorporated herein by reference is the information under Environmental Matters in Item 7.

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

No matters were submitted during the fourth quarter of fiscal year 2003.

Executive Officers of the Registrant

The executive officers of the Company, as of December 1, 2003, are as follows:

Name	Office	Age	Year Became Officer
W. Brian Matsuyama	President and Chief Executive Officer	57	1987
J. D. Wessling	Chief Financial Officer	60	1995
William H. Odell	Chief Operating Officer	41	2000
Jon T. Stoltz	Senior Vice President - Gas Supply and Regulatory Affairs	56	1981
Larry C. Rosok	Vice President - Human Resources and Corporate Secretary	47	1995
James E. Haug	Controller	54	1981

None of the above officers is related by blood, marriage or adoption to any other of the above named officers. Each of the above named officers has been employed by the Company in a management capacity for at least the past five years. None of the above officers hold directorships in other public corporations. All officers serve at the pleasure of the Board of Directors.

PART II

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

The Common Stock is traded on the New York Stock Exchange under the symbol CGC. The following table states the per share high and low sales prices of the Common Stock.

	Fiscal 2003		Fiscal 2002	
Quarter	**High**	**Low**	**High**	**Low**
December 31	$ 20.44	$ 17.70	$ 22.77	$ 19.62
March 31	20.24	18.05	21.98	18.21
June 30	20.15	18.20	24.17	19.90
September 30	20.24	18.00	23.80	15.53

At September 30, 2003, there were 6,500 holders of the Common Stock. The following table shows for the periods indicated the dividends paid per share on the Common Stock.

Quarter	**Fiscal 2003**	**Fiscal 2002**
December 31	$ 0.24	$ 0.24
March 31	$ 0.24	$ 0.24
June 30	$ 0.24	$ 0.24
September 30	$ 0.24	$ 0.24

Various debt and credit agreements restrict the Company and its subsidiaries as to indebtedness, payment of cash dividends on common stock, and other matters. Under the most conservative restriction, approximately $12,946,000 was available for payment of dividends as of September 30, 2003.

Item 6. Selected Financial Data

Consolidated Statements of Income and Comprehensive Income:

(dollars in thousands except per share data)

	Year Ended September 30				
	2003	**2002**	**2001**	**2000**	**1999**
Operating Revenues	$ 302,755	$ 320,978	$ 335,814	$ 241,936	$ 208,610
Less: Gas Purchases	191,887	209,225	219,795	136,681	109,263
Revenue taxes	20,193	21,251	20,987	15,261	13,280
Operating Margin	90,675	90,502	95,032	89,994	86,067
Cost of Operations:					
Operating expenses	45,514	43,052	41,027	38,808	38,166
Depreciation and amortization	15,338	14,926	13,839	13,293	12,841
Property and payroll taxes	3,532	3,361	3,182	2,896	2,721
	64,384	61,339	58,048	54,997	53,728
Income From Operations	26,291	29,163	36,984	34,997	32,339
Nonoperating Expense (Income):					
Interest	12,363	12,384	10,509	10,936	10,486
Interest charged to construction	(378)	(219)	(333)	(322)	(383)
	11,985	12,165	10,176	10,614	10,103
Amortization of debt issuance expense	696	652	607	607	603
Other	(227)	(197)	(313)	(649)	(495)
	12,454	12,620	10,470	10,572	10,211
Income Before Income Taxes	13,837	16,543	26,514	24,425	22,128
Income Taxes	4,733	5,781	9,278	9,051	8,075
Net Income Before Preferred Dividends	9,104	10,762	17,236	15,374	14,053
Preferred Dividends				4	483
Net Income	$ 9,104	$ 10,762	$ 17,236	$ 15,370	$ 13,570
Other Comprehensive Income (Loss)					
Minimum pension liability adjustment	$ (2,619)	$ (11,792)	$ (6,502)	$	$

Income tax benefit		937		4,205		2,341				
Other Comprehensive Income (Loss)	$	(1,682)	$	(7,587)	$	(4,161)	$		$	
Comprehensive Income	$	7,422	$	3,175	$	13,075	$	15,370	$	13,570
Earnings Per Common Share, Basic and Diluted	$	0.82	$	0.97	$	1.56	$	1.39	$	1.23

	At September 30				
	2003	2002	2001	2000	1999
Retained Earnings:					
Beginning of the year	$ 17,524	$ 17,369	$ 10,736	$ 5,970	$ 3,003
Net income	9,104	10,762	17,236	15,370	13,570
Exercise of stock options		(4)			
Common dividends	(10,647)	(10,603)	(10,603)	(10,604)	(10,603)
End of the year	$ 15,981	$ 17,524	$ 17,369	$ 10,736	$ 5,970
Capital Structure:					
Common shareholders equity	$ 112,560	$ 114,181	$ 121,633	$ 119,161	$ 114,395
Redeemable preferred stocks				62	6,186
Debt:					
Long-term debt	142,930	164,930	125,000	125,000	125,000
Notes payable and commercial paper	3,800		40,000	1,500	
Current maturities of long-term debt	22,000				
	168,730	164,930	165,000	126,500	125,000
Total capital	$ 281,290	$ 279,111	$ 286,633	$ 245,723	$ 245,581
Financial Ratios:					
Return on common shareholders equity	7.62%	8.49%	13.45%	12.51%	11.52%
Common stock dividend payout ratio	117%	99%	62%	69%	78%
Cash dividends declared per common share	$ 0.96	$ 0.96	$ 0.96	$ 0.96	$ 0.96
Fixed charge coverage (before income tax deduction):					
Times interest earned	2.06	2.27	3.39	3.12	3.00
Times interest and preferred dividends earned	2.06	2.27	3.39	3.12	2.80
Book value per year-end share of common stock	$ 10.11	$ 10.34	$ 11.01	$ 10.79	$ 10.33
Capitalization Ratios at End of Year					
Common shareholders equity	40.0%	40.9%	42.4%	48.5%	46.6%
Preferred stock	0.0%	0.0%	0.0%	0.0%	2.5%
Long-term debt (incl. current)	58.6%	59.1%	43.6%	50.9%	50.9%
Short-term debt	1.4%	0.0%	14.0%	0.6%	0.0%
	100.0%	100.0%	100.0%	100.0%	100.0%
Utility Plant:					
Utility plant - end of year	$ 529,807	$ 505,126	$ 488,231	$ 468,789	$ 453,278
Accumulated depreciation	227,582	213,476	201,530	189,058	177,878
Net plant	$ 302,225	$ 291,650	$ 286,701	$ 279,731	$ 275,400

Capital expenditures, net of contributions in aid	$ 27,693	$ 20,734	$ 21,649	$ 15,937	$ 17,262
Total assets	$ 371,456	$ 367,663	$ 364,253	$ 328,336	$ 315,569

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

The following is management s assessment of the Company s financial condition and a discussion of the principal factors that affect consolidated results of operations and cash flows for the fiscal years ended September 30, 2003, 2002, and 2001. References herein to 2003, 2002, and 2001 refer to these fiscal years.

CRITICAL ACCOUNTING POLICIES

The Company s financial statements are prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). In following GAAP, management exercises judgment in selection and application of accounting principles. Management considers Critical Accounting Policies to be those where different assumptions regarding application could result in material differences in financial statements.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. The Company has used estimates in measuring certain deferred charges and deferred credits related to items subject to approval of the WUTC and the OPUC. Estimates are also used in the development of discount rates and trend rates related to the measurement of retirement benefit obligations and accrual amounts, allowances for doubtful accounts, unbilled revenue, valuation of derivative instruments, and in the determination of depreciable lives of utility plant. On an ongoing basis, management evaluates the estimates used, based on historical experience, current conditions and on various other assumptions believed to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions.

Revenue Recognition

The Company recognizes operating revenues based on deliveries of gas and other services to customers. This includes estimated revenues for gas delivered but not billed to residential and commercial customers from the latest meter reading date to the end of the accounting period.

The Company recognizes operating revenues based on deliveries of gas and other services to customers. This incl

Regulatory Accounting

The Company s accounting policies and practices are generally the same as used by unregulated companies for financial reporting under GAAP. However, Statement of Financial Accounting Standards (FAS) No. 71, Accounting for the Effects of Certain Types of Regulation , requires regulated companies to apply special accounting treatment to reflect the financial impact of regulation. For example, in establishing the rates to be charged to the Company s retail customers, the Washington Utilities and Transportation Commission (WUTC) and the Oregon Public Utility Commission (OPUC) may not allow the Company to charge its customers for recovery of certain expenses in the same period they are incurred. Instead, rates are established in the future to recover costs that were incurred in a prior period. In this situation, FAS No. 71 requires the Company to defer these costs and include them as regulatory assets on the balance sheet. In the subsequent period when these costs are recovered from customers, the Company then amortizes these costs as expense in the income statement, in an amount equivalent to the amounts recovered. Similarly, certain revenue items, or cost reductions may be deferred as regulatory liabilities, which are later amortized to the income statement as customer rates are reduced.

In order to apply the provisions of FAS No. 71, the following conditions must apply:

An independent regulator approves the company s customer rates.

The rates are designed to recover the company s costs of providing the regulated services or products.

There is sufficient demand for the regulated service to reasonably assure that rates can be set at a level to recover the costs.

The Company periodically assesses whether conditions merit the continued applicability of FAS No. 71. In the event the Company should determine in the future that all or a portion of its regulatory assets and liabilities no longer meet the above criteria, it would be required to write off the related balances of its regulatory assets and liabilities, and reflect the write off in its income statement. At September 30, 2003 there were $13,963,000 of regulatory assets and $4,399,000 of regulatory liabilities.

Pension Plans

The Company has a defined benefit pension plan covering substantially all employees over 21 years of age with one year of service. The Company also provides executive officers with supplemental retirement, death and disability benefits. Descriptions of these plans, including plan changes adopted in 2003, are included in Note 10 to the Consolidated Financial Statements, as well as in Item 7 under Employee Benefits Plan Changes .

The Company s pension costs for these plans are affected by the amount of cash contributions to the plans, the return on plan assets, and by employee demographics, including age, compensation, and length of service. Actuarial formulas are used in the determination of pension costs, and are affected by actual plan experience and assumptions of future experience. Key actuarial assumptions include the expected return on plan assets, the discount rate used in determining the projected benefit obligation and pension costs, and the assumed rate of increase in employee compensation. Changes in these assumptions may significantly affect pension costs. Changes to the provisions of the plans may also impact current and future pension costs. Changes in pension plan obligations resulting from these factors may not be immediately recognized as pension costs, but generally are recognized in future years over the remaining average service period of pension plan participants.

The Company s funding policy is to contribute amounts equal to or greater than the minimum amounts required to be funded under the Employee Retirement Income Security Act, and not more than the maximum amounts currently deductible for income tax purposes. The Company contributed $4,412,000 in 2002 and $4,269,000 in 2003 to the pension and supplemental executive retirement plans, and expects to contribute $3,500,000 in 2004.

In selecting a discount rate, the Company uses the average of the 20 year and above Aaa, Aa, A, and Baa rates published by Moody s. These are rates considered to be consistent with the expected term of pension benefits. In 2003 the Company reduced the discount rate from 6.75% to 6.25% in connection with remeasurement of the pension obligation at May 1, 2003, with a further reduction to 6.00% at September 30, 2003. A reduction in the discount rate results in increases in projected benefit obligation, pension liability, and pension costs.

In selecting an assumed long-term rate of return on plan assets, the Company considers past performance and economic forecasts for the types of investments held by the plan. In 2002 and 2003 the Company s assumed rate of return on plan assets was 8.25%. A reduction in the assumed rate of return would result in increases in pension liability and pension costs. The general downward trend in equity markets in 2001 and 2002 and a partial recovery in 2003 have affected the value of the Company s plan assets. Additional information regarding the impact of these market declines is included in Item 7 under Other Comprehensive Income (Loss) , and in Note 10 to the Consolidated Financial Statements.

Derivatives

The company accounts for derivative transactions according to the provisions of FAS No. 133, as amended by FAS No. 138 and by FAS No. 149. These standards require that the fair value of all derivative financial instruments be recognized as either assets or liabilities on the Company s balance sheet and the recognition of unrealized gains and losses.

The Company s contracts for purchase and sale of natural gas qualify for the normal purchase and normal sales exceptions under FAS No. 133 and are not required to be recorded as derivative assets and liabilities. Accordingly, the Company recognizes revenues and expenses on an accrual basis, based on physical delivery of natural gas. The company applies mark-to-market accounting to financial derivative contracts. Periodic changes in fair market value are recognized in earnings.

The differences in accounting for purchases and sales contracts versus financial contracts do not change the underlying economics of the transactions, but could result in increased quarterly earnings volatility.

New Accounting Standards:

See Note 2 to the Consolidated Financial statements.

EARNINGS PER SHARE

Net income for 2003 was $9,104,000 compared to $10,762,000 for 2002. Basic and diluted earnings per share for 2003 were $0.82, a 15% decrease from the $0.97 per share earnings for 2002.

2002 versus 2001. Net income was $10,762,000 for 2002, compared to $17,236,000 for 2001. Basic and diluted earnings per share for 2002 were $0.97, a 38% decrease from the $1.56 reported for 2001.

OPERATING MARGIN

Operating margins by customer category for the fiscal years ended September 30, 2003, 2002 and 2001are set forth in the tables below:

Residential and Commercial Margin

($ in thousands)	(12 months ended September 30) 2003	2002	2001
Degree Days	5,042	5,455	5,793
Average Number of Customers			
Residential	177,300	169,454	163,427
Commercial	28,851	28,216	27,796
Average Therm Usage Per Customer			
Residential	692	763	776
Commercial	3,473	3,802	4,023
Operating Margin			
Residential	$ 37,483	$ 38,396	$ 37,619
Commercial	$ 21,014	$ 22,209	$ 23,073

Industrial and Other Margin

($ and therms in thousands)	(12 months ended September 30) 2003	2002	2001
Average Number of Customers			
Electric Generation	14	12	8
Industrial	741	755	746
Therms Delivered			
Electric Generation	543,621	591,653	956,701
Industrial	395,480	373,252	386,872
Operating Margin			
Electric Generation	$ 9,032	$ 9,263	$ 11,420
Industrial	$ 19,394	$ 19,194	$ 18,849
Gas Management Services	$ 3,509	$ 370	$ 997
Other	$ 243	$ 1,070	$ 3,074

2003 Versus 2002

Total operating margin of $90,675,000 was only slightly greater than prior year margin of $90,502,000. Declines in margins from residential and commercial customers were substantially offset by improvements in margins from industrial and other customers.

Residential and Commercial. Margins from residential and commercial customers declined $2,108,000. Weather, 7.6% warmer in 2003 compared to 2002, contributed to declines in per-customer gas consumption. The resulting impact on margin was a reduction of approximately $4,600,000. Partially offsetting this decline was a positive impact from the addition of new customers, which contributed approximately $2,600,000 margin.

Industrial and Other. Margins from delivery of gas to electric generation customers declined $231,000. Lower margins from electric generation customers in 2003 reflect continued sluggish economic conditions and adequate supplies of lower cost hydropower displacing electricity from gas generation facilities.

Margins from delivering gas to industrial customers increased slightly, substantially offsetting the decline from electric generation customers.

Margins from gas management services to customers were negatively affected in both years by termination charges in settlement of two cancelled gas supply contracts. The contracts were entered into to provide supplies to a group of industrial customers who had contracted for gas management services. In 2002 an initial charge of $2,800,000 was recorded reflecting management s estimate at that time of the estimated liability under the claims. An additional charge of $865,000 was recorded in 2003 reflecting full settlement of all claims related to these contracts.

In the fourth quarter of fiscal 2003, the Company entered into cap and swap derivative arrangements, effectively fixing the price for supplies to be purchased for delivery to gas management customers beginning in 2004. As prescribed in FAS No. 133, the Company applies mark-to-market accounting to these derivatives. After entering into the derivative arrangements, the market price of gas declined, resulting in a mark-to-market charge of $315,000, reflected in gas management margins. A significant portion of gas management service margins is derived from arranging gas supplies for these customers. As these arrangements expire and new ones are entered into, margins will fluctuate.

Other margins declined $837,000. In 2003 other margins included a charge of $351,000 related to an estimated liability under an earnings-sharing requirement of the Oregon Public Utilities Commission. Under that arrangement, the Company is required to defer, for refund to Oregon customers, 33% of amounts determined under a prescribed formula to be in excess of authorized earnings attributable to regulated operations in that state. In 2002, other margins included $347,000 of revenue from an off-system interstate pipeline transaction entered into in 2001.

2002 versus 2001.

Operating margins in 2002 were $90,502,000, a decline of $4,530,000 from 2001, with $2,738,000 of the decline attributed to revenue in 2001 from the sale of off-system interstate pipeline capacity, and another $2,800,000 contract termination charge recorded in 2002. Other components of changes in operating margin are described in the paragraphs below.

Residential and Commercial. Operating margins from residential and commercial customers were essentially even with fiscal year 2001. Increases in the number of residential and commercial customers contributed approximately $1,990,000 of new margin. Temperatures, 6% warmer than 2001, contributed to a consumption decline, the effect of which substantially offset the improvement from new customer additions.

Industrial and Other. Operating margins from electric generation customers were $2,157,000 lower than fiscal year 2001. The slow economy, mild temperatures, and higher than normal hydroelectric generation dramatically affected demand for gas-fired generation throughout the year but particularly during the third and fourth quarters. The fourth quarter alone was down $979,000 from the prior year.

Margins in 2002 from providing gas management services to customers were negatively affected by a charge related to settlement of termination charges related to cancellation of a gas supply contract. The contract had been entered into to provide supplies to a group of industrial customers who had contracted for gas management services. In 2002 a charge of $2,800,000 was recorded reflecting management s estimate at that time of the estimated liability under the claim.

Other margins declined $2,004,000 from 2001, largely related to opportunities in 2001 to enter into two off-system interstate pipeline transactions. These transactions resulted in $3,074,000 of operating margin in 2001, and $386,000 in 2002. The Company has no expectation of additional revenues from such sources, and this is not an on-going part of Cascade s business.

COST OF OPERATIONS

Cost of operations, which consists of operating expenses, depreciation and amortization, and property and payroll taxes, was $64,384,000, $61,339,000, and $58,048,000 for the fiscal years ended September 30, 2003, 2002, and 2001, respectively.

2003 versus 2002

Operating Expenses increased $2,462,000, 5.7% over 2002, including an increase in employee benefits expenses of $1,946,000. Included in benefits expense was recognition of a $1,451,000 curtailment loss in connection with changes in the Company s retirement plans for salaried employees and executives. The revisions to the defined benefit plans constitute plan curtailments under FAS No. 88, *Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefit*, resulting in the above-mentioned curtailment loss associated with unrecognized prior service cost and transition obligation. Further information on benefits plan changes is included below under Employee Benefits Plan Changes .

Also contributing to the increase in operating expenses is a $524,000 charge for accrual of severance costs, and a $701,000 increase in purchased services, stemming primarily from consulting charges related to two projects, the Company s review of its benefit plans, and a project to prepare the Company for the compliance requirements of the Sarbanes-Oxley Act.

Depreciation and Amortization increased $412,000, 2.8%, over 2002 primarily as a result of increases in depreciable gas distribution system assets.

Property and Miscellaneous Taxes increased $171,000, 5.1% over 2002 related to increases in taxable property.

2002 versus 2001

Operating Expenses for 2002 increased $2,025,000, or 4.9% from 2001. Employee benefits expense increased $2,030,000 over 2001. The bulk of the increase is due to increasing costs of the Company s medical benefit plans for active and retired employees. In the aggregate, other expense categories decreased, due primarily to the inclusion in 2001 of $857,000 related to the installation of a new integrated work management system. Also included in 2002 operating expenses is a $250,000 charge for the settlement of a lawsuit filed against the Company in 1998 in connection with personal injury claims.

Depreciation and Amortization for 2002 increased $1,087,000 or 7.9% over 2001. The increase is primarily attributable to the depreciation on computer system investments in fiscal 2001 and natural gas distribution assets added since the previous year. Fiscal 2002 was the first full-year of depreciation on the integrated work management system installed at the end of 2001.

Property and Miscellaneous Taxes for 2002 increased $179,000 or 5.6% over 2001 related to increases in taxable property.

EMPLOYEE BENEFITS PLAN CHANGES

The Company has conducted a comprehensive review of its employee benefits plans, and in the third quarter of fiscal 2003 began to implement significant changes to its employee retirement plan, executive retirement plan and healthcare plans for both active employees and retirees. The changes apply to the Company s non-bargaining-unit employees, and are designed to reduce benefits costs by an estimated $3.0 to $3.5 million per year, beginning in fiscal 2004. The changes are also designed to reduce future volatility in benefits expenses and facilitate management control over future cost increases, while retaining a benefits package management believes is competitive. Though some cost reductions occurred in fiscal 2003, these reductions were offset by costs of implementing the changes, including the charge described below.

Some of the changes involve the Company s employee retirement plan and executive supplemental retirement plan. As of September 30, 2003 these defined benefit plans stopped accruing additional benefits. Instead, defined contribution plans will be used for benefits earned beginning October 1, 2003. The revisions to the defined benefit plans constitute plan curtailments under FAS No. 88, *Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits.* Therefore, the company recorded a charge to operating expense of approximately $1,451,000 in the third quarter of fiscal 2003, as a curtailment loss associated with unrecognized prior service cost and transition obligation.

NONOPERATING EXPENSE (INCOME)

2003 versus 2002

Net non-operating expense (income) decreased slightly from 2002, primarily due to a $159,000 increase in interest charged to construction.

2002 versus 2001

Interest expense in 2002, net of interest capitalized, increased $1,989,000 (19.5%) from 2001, due to the issuance of $40,000,000, 7.5 % 30 year notes in November of 2001. Interest on these notes exceeded interest on the short-term debt they replaced.

INCOME TAXES

The changes in the provision for income taxes from 2002 to 2003, and from 2001 to 2002 are directly attributable to the changes in pre-tax earnings.

OTHER COMPREHENSIVE INCOME (LOSS)

During fiscal years 2001 and 2002, the value of the pension plan assets declined, reflecting the general downward trend in common stock values. Asset values recovered somewhat in 2003. The 2001 and 2002 declines in asset values, along with a decrease in the assumed discount rate to 6% in 2003 from 7.50% in 2001, and a reduction in the earnings assumption rate to 8.25% in 2002 and 2003 from the 9.0% 2001 rate, resulted in an unfunded accumulated benefit obligation. To recognize this liability, the Company recorded charges to Other Comprehensive Income (Loss) for minimum pension liability adjustments of $9,647,000 in 2001, $11,875,000 in 2002, and $2,619,000 in 2003, in accordance with the provisions of FAS No. 87. Other comprehensive loss also includes credits for the deferred income tax effect of $937,000, $4,205,000 and $2,341,000 for 2003, 2002 and 2001 respectively.

LIQUIDITY AND CAPITAL RESOURCES

The seasonal nature of the Company s business creates short-term cash requirements to finance customer accounts receivable and construction expenditures. To provide working capital for these requirements, the Company has a $50,000,000 bank revolving credit commitment. This agreement has an annual 0.16% commitment fee, and a term that expires in November 2004. The Company also has a $10,000,000 uncommitted bank credit line. As of September 30, 2003, there was $3,800,000 outstanding debt under these credit lines.

To provide longer-term financing, the Company in 2001 filed an omnibus registration statement under the Securities Act of 1933 providing the ability to issue up to $150,000,000 of new debt and equity securities. In fiscal 2002 the Company issued $40,000,000 of 7.5% 30-year debt under the omnibus registration statement, leaving $110,000,000 available under that registration statement for future financing. The proceeds of the $40,000,000 offering were used to pay down outstanding short-term debt.

Because of the availability of short-term credit and the ability to issue long-term debt and additional equity, management believes it has adequate financial flexibility to meet its anticipated cash needs.

OPERATING ACTIVITIES

For fiscal 2003, operating activities provided cash of $36,700,000, substantially equivalent to the $36,004,000 for 2002. Included in these amounts were $5,868,000 and $8,270,000 for amortization of deferred gas cost changes. This is primarily related to inclusion in customer rates of a component to recover under-recovered gas cost from the winter of fiscal 2001. In fiscal 2002 the WUTC approved this temporary rate increase designed to recover the 2001 under-recovery by October 2004.

INVESTING ACTIVITIES

Cash used by investing activities in 2003 was $27,693,000, compared to $20,551,000 in 2002. Investing activities are substantially all capital expenditures, and included $3,683,000 for a project to automate meter reading (AMR). Approximately $19,000,000 of 2003 capital expenditures were dedicated to connecting new customers.

Budgeted capital expenditures for fiscal 2004 are approximately $35,000,000, which includes $10,000,000 for the AMR project, with the remainder for new customer connections, distribution system reinforcement and replacement projects, equipment, facilities upgrades, and various technology projects. The AMR project is planned to be completed in the first quarter of fiscal 2005, resulting in savings in meter reading expenses when fully phased in by the second quarter of 2005.

FINANCING ACTIVITIES

Financing activities for 2003 used cash of $5,243,000 compared to $12,187,000 for 2002. Other than the payment of dividends, the primary financing activity in 2003 was the $3,800,000 net increase in short-term debt. The Company also received $1,604,000 from the issuance of new common stock. In 2003, the Company began issuing new stock to its dividend reinvestment plan and 401(k) plans, and on exercise of stock options. The prior practice was to use funds received to purchase shares of stock on the open market. In 2002 the primary financing activity was the replacement of $40,000,000 short-term debt with proceeds from issuance of new 7.5% 30-year notes.

ENVIRONMENTAL MATTERS

In 1995, the Company received a claim from a property owner in Eugene, Oregon requesting that the Company assume responsibility for investigation and possible clean up of alleged contamination on property previously owned by a predecessor of Cascade. The predecessor company conducted a manufactured gas business on the property from approximately 1929 to 1948. Manufactured gas operations apparently were conducted on the site by several operators beginning about 1907. The site was used for other purposes beginning in 1949.

The present owner has retained an environmental consultant, who is investigating possible contamination on the property. To date the consultant has reported that it believes contamination is present. The contamination is consistent with that which might originate from a manufactured gas operation. There have been no estimates as to possible clean up costs. The consultant s initial report has been furnished to the Oregon Department of Environmental Quality (DEQ). The owner has reached an intergovernmental agreement with the DEQ with respect to further investigation and possible remediation of contamination on the property under the voluntary cleanup program.

Another northwest utility, which purchased the property from Cascade in 1958, has declined to participate in the site investigation, although it may, as a one-time owner of the property, bear some share of the responsibility as well.

The Company has notified its insurance carriers of the claim and is keeping them advised as to the investigation. On one occasion in the past when hazardous materials on property formerly owned by a predecessor of the Company required clean up, the OPUC allowed the clean up costs to be passed on to customers. In the event the Company is responsible for clean up costs not covered by insurance, management anticipates asking for reimbursement through rates for such costs.

In 1997, a property owner in Washington notified the Company that there is contamination on his property, and that he believes it comes from a former manufactured gas site, owned at one time by a predecessor company, which was merged with Cascade in 1953. The State of Washington Department of Ecology has categorized this site as a listed site ranked in its most hazardous category. As a former owner of the site, the Company may be strictly liable to the State of Washington for investigation and remediation of the contamination of the site, but may share that cost or allocate all the cost to others who actually caused or contributed to the contamination.

The Company retained an environmental consultant who conducted a preliminary investigation of possible contamination at the site. There is evidence of contamination at the site, and there is also evidence of an oil line across the site property owned and operated by others, which may be a contributor to the contamination. There have been no estimates as to possible clean up costs. The Company has investigated title and other government records to identify other potentially liable parties. The Company has notified the other identified parties of the contamination claims, and has requested cooperation and financial contribution.

In the event the Company is responsible for clean up costs not covered by insurance, management anticipates asking the WUTC for reimbursement for such costs, through rates charged to customers.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Cascade has evaluated its risk related to financial instruments whose values are subject to market sensitivity. The Company has fixed-rate debt obligations, but does not have derivative financial instruments subject to interest rate risk. Cascade makes interest and principal payments on these obligations in the normal course of its business, and does not plan to redeem these obligations prior to normal maturities.

The Company s natural gas purchase commodity prices are subject to fluctuations resulting from weather, congestion on interstate pipelines, and other unpredictable factors. The Company s PGA mechanisms assure the recovery of prudently incurred wholesale cost of gas purchased for the core market. The Company utilizes fixed price contracts and financial derivatives to manage risk associated with wholesale costs of gas purchased for non-core customers.

FORWARD-LOOKING STATEMENTS

Statements contained in this report that are not historical in nature are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements are subject to risks and uncertainties that may cause actual future results to differ materially. Such risks and uncertainties with respect to the Company include, among others, its ability to successfully implement internal performance goals, competition from alternative forms of energy, consolidation in the energy industry, performance issues with key natural gas suppliers, the capital-intensive nature of the Company s business, regulatory issues, including the need for adequate and timely rate relief to recover increased capital and operating costs resulting from customer growth and to sustain dividend levels, the weather, increasing competition brought on by deregulation initiatives at the federal and state regulatory levels, the potential loss of large volume industrial customers due to bypass or the shift by such customers to special competitive contracts at lower per unit margins, exposure to environmental cleanup requirements, and economic conditions, particularly in the Company s service area.

Item 8. Financial Statements and Supplementary Data

INDEPENDENT AUDITORS REPORT

Board of Directors

Cascade Natural Gas Corporation

Seattle, Washington

We have audited the accompanying consolidated balance sheets of Cascade Natural Gas Corporation and subsidiaries (the Corporation) as of September 30, 2003 and 2002, and the related consolidated statements of income and comprehensive income, common shareholders equity, and cash flows for each of the three years in the period ended September 30, 2003. Our audits also included the financial statement schedule contained in Item 15(a)-2. These financial statements and financial statement schedule are the responsibility of the Corporation s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements and financial statement schedule present fairly, in all material respects, the financial position of Cascade Natural Gas Corporation and subsidiaries as of September 30, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2003, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP

Seattle, Washington
November 21, 2003

CASCADE NATURAL GAS CORPORATION

CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(Dollars in thousands except per share data)

	Year Ended September 30,		
	2003	**2002**	**2001**
Operating Revenues	$ 302,755	$ 320,978	$ 335,814
Less			
Gas purchases	191,887	209,225	219,795
Revenue taxes	20,193	21,251	20,987
Operating Margin	90,675	90,502	95,032
Cost of Operations			
Operating expenses	45,514	43,052	41,027
Depreciation and amortization	15,338	14,926	13,839
Property and miscellaneous taxes	3,532	3,361	3,182
	64,384	61,339	58,048
Income from operations	26,291	29,163	36,984
Nonoperating Expense (Income)			
Interest	12,363	12,384	10,509
Interest charged to construction	(378)	(219)	(333)
	11,985	12,165	10,176
Amortization of debt issuance expense	696	652	607
Other	(227)	(197)	(313)
	12,454	12,620	10,470
Income Before Income Taxes	13,837	16,543	26,514
Income Taxes	4,733	5,781	9,278
Net Income	$ 9,104	$ 10,762	$ 17,236
Other Comprehensive Income (Loss):			
Minimum pension liability adjustment	$ (2,619)	$ (11,792)	$ (6,502)
Income tax benefit	937	4,205	2,341
Other Comprehensive Income (Loss)	$ (1,682)	$ (7,587)	$ (4,161)
Comprehensive Income	$ 7,422	$ 3,175	$ 13,075
Earnings Per Common Share, Basic and Diluted	$ 0.82	$ 0.97	$ 1.56
Dividends Paid Per Common Share	$ 0.96	$ 0.96	$ 0.96

The accompanying notes are an integral part of these financial statements

CASCADE NATURAL GAS CORPORATION

CONSOLIDATED BALANCE SHEETS

	September 30,	
	2003	2002
	(Dollars in thousands)	
ASSETS		
Utility Plant	$ 529,807	$ 505,126
Less accumulated depreciation	227,582	213,476
	302,225	291,650
Construction work in progress	10,078	7,974
	312,303	299,624
Other Assets		
Investments in non utility property	202	202
Notes receivable, less current maturities	52	127
	254	329
Current Assets		
Cash and cash equivalents	7,452	3,688
Accounts receivable and current maturities of notes receivable, less allowance of $877 and $1,126 for doubtful accounts	12,296	14,547
Materials, supplies, and inventories	14,737	14,556
Prepaid expenses and other assets	6,144	6,515
Deferred income taxes	755	1,648
	41,384	40,954
Deferred Charges and Other		
Gas cost changes	11,584	18,788
Other	5,931	7,968
	17,515	26,756
	$ 371,456	$ 367,663

	September 30,	
	2003	2002
	(Dollars in thousands)	
COMMON SHAREHOLDERS EQUITY AND LIABILITIES		
Common Shareholders Equity		
Common stock, par value $1 per share; Authorized, 15,000,000 shares Issued and outstanding, 11,131,860 and 11,045,095 shares	$ 11,132	$ 11,045
Additional paid-in capital	98,877	97,360
Accumulated other comprehensive income (loss)	(13,430)	(11,748)
Retained earnings	15,981	17,524
	112,560	114,181
Long-Term Debt	142,930	164,930
Current Liabilities		
Notes payable and commercial paper	3,800	
Current maturities of long-term debt	22,000	
Accounts payable	10,501	12,597
Property, payroll, and excise taxes	5,387	5,777
Dividends and interest payable	7,884	7,872
Other current liabilities	6,431	9,466
	56,003	35,712
Deferred Credits and Other		
Income taxes	23,292	20,299
Investment tax credits	1,479	1,669
Other	35,192	30,872
	59,963	52,840
Commitments and Contingencies (Note 11)		
	$ 371,456	$ 367,663

The accompanying notes are an integral part of these financial statements

CASCADE NATURAL GAS CORPORATION

CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS EQUITY

(Dollars in thousands except per share data)	Common Stock Shares	Common Stock Par Value	Paid-In Capital	Accumulated Other Comprehensive Income	Retained Earnings
Balance, September 30, 2000	11,045,095	$ 11,045	$ 97,380	$ $	10,736
Cash dividends:					
Common stock, $.96 per share					(10,603)
Other comprehensive income (loss)				(4,161)	
Net Income					17,236
Balance, September 30, 2001	11,045,095	$ 11,045	$ 97,380	$ (4,161)	$ 17,369
Cash dividends:					
Common stock, $.96 per share					(10,603)
Other comprehensive income (loss)				(7,587)	
Exercise of stock options			(20)		(4)
Net Income					10,762
Balance, September 30, 2002	11,045,095	$ 11,045	$ 97,360	$ (11,748)	$ 17,524
Cash dividends:					
Common stock, $.96 per share					(10,647)
Other comprehensive income (loss)				(1,682)	
Issuance of common stock	86,765	87	1,517		
Net Income					9,104
Balance, September 30, 2003	11,131,860	$ 11,132	$ 98,877	$ (13,430)	$ 15,981

The accompanying notes are an integral part of these financial statements

CASCADE NATURAL GAS CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Dollars in thousands)

	Year Ended September 30,		
	2003	**2002**	**2001**
Operating Activities			
Net Income	$ 9,104	$ 10,762	$ 17,236
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	15,338	14,926	13,839
Deferrals of gas cost changes	1,336	1,804	(40,801)
Amortization of gas cost changes	5,868	8,270	(3,108)
Other deferrals and amortizations	6,032	(2,559)	3,706
Deferred income taxes and tax credits - net	2,804	3,541	1,403
Change in current assets and liabilities	(3,782)	(740)	(271)
Net cash provided (used) by operating activities	36,700	36,004	(7,996)
Investing Activities			
Capital expenditures	(28,551)	(21,117)	(23,829)
Customer contributions in aid of construction	858	383	2,180
Other		183	100
Net cash used by investing activities	(27,693)	(20,551)	(21,549)
Financing Activities			
Proceeds from long-term debt, net		38,510	
Repayment of long-term debt		(70)	
Changes in notes payable and commercial paper, net	3,800	(40,000)	38,500
Proceeds from issuance of common stock	1,604		
Dividends paid	(10,647)	(10,603)	(10,603)
Redemption of preferred stock			(62)
Other		(24)	
Net cash provided (used) by financing activities	(5,243)	(12,187)	27,835
Net Increase (Decrease) in Cash and Cash Equivalents	3,764	3,266	(1,710)
Cash and Cash Equivalents			
Beginning of year	3,688	422	2,132
End of year	$ 7,452	$ 3,688	$ 422

The accompanying notes are an integral part of these financial statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Nature of Business

Cascade Natural Gas Corporation (the Company) is a local distribution company (LDC) engaged in the distribution of natural gas. The Company s service territory consists of towns in Washington and Oregon, ranging from the Canadian border in northwestern Washington to the Idaho border in eastern Oregon.

As of September 30, 2003, the Company had approximately 206,000 billed core customers and 206 non-core customers. Core customers are principally residential and small commercial and industrial customers who take traditional bundled natural gas service, which includes supply, peaking service, and upstream interstate pipeline transportation. Sales to core customers account for approximately 21% of gas deliveries and 68% of operating margin. The Company s sales to its core residential and commercial customers are influenced by fluctuations in temperature, particularly during the winter season. A warm winter season will tend to reduce gas consumption. Over the longer term, these fluctuations tend to offset each other, as rates charged to customers are developed based on the assumption of normal weather.

Non-core customers are generally large industrial, electric generation, and institutional customers who have chosen unbundled service, meaning that they select from among several supply and upstream pipeline transportation options, independent of the Company s distribution service. The Company s margin from non-core customers is derived primarily from this distribution service, as well as gas management services. The principal industrial activities of its customers include the generation of electricity, processing of food, processing of forest products, production of chemicals, and refining of crude oil.

The Company is subject to regulation of most aspects of its operations by the Washington Utilities and Transportation Commission (WUTC) and the Oregon Public Utility Commission (OPUC). It is subject to regulatory risk primarily with respect to recovery of costs incurred. Various deferred charges and deferred credits reflect assumptions regarding recovery of certain costs through temporary customer rate adjustments during future periods.

Note 2 - Summary of Significant Accounting Policies

The Company s accounting records and practices conform to the requirements of the uniform system of accounts prescribed by the WUTC and the OPUC.

Principles of consolidation: The consolidated financial statements include the accounts of Cascade Natural Gas Corporation and its wholly owned subsidiaries: Cascade Land Leasing Co.; CGC Properties, Inc.; CGC Energy, Inc.; and CGC Resources, Inc. All intercompany transactions are eliminated in consolidation.

Reclassifications: Certain reclassifications have been made in the 2002 and 2001 financial statements to conform to the classifications used in 2003.

Utility plant: Utility plant is stated at the historical cost of construction or purchase. These costs include payroll-related costs such as taxes and other employee benefits, general and administrative costs, and the estimated cost of funds used during construction. Maintenance and repairs of property, and replacements and renewals of items deemed to be less than units of property, are charged to operations. Units of utility plant retired or replaced are credited to property accounts at cost. Such amounts plus removal cost, less salvage, are charged to accumulated depreciation. In the case of a sale of non-depreciable property or major operating units, the resulting gain or loss on the sale is included in other income or expense.

Depreciation of utility plant is computed using the straight-line method. The Company periodically conducts depreciation studies to establish and update asset depreciation lives. Asset lives used for computing depreciation range from six to seventy years, and the weighted average annual depreciation rate is approximately 3.0%. The Company periodically reviews the carrying amount of its utility plant and other long-lived assets for impairment. An asset is considered impaired when estimated future cash flows are less than the carrying amount of the asset. In the event the carrying amount of such asset is deemed not recoverable, the asset is adjusted to its fair value. Fair value is generally determined based on discounted future cash flow.

Investments in non-utility property: Real estate, carried at the lower of cost or estimated net realizable value is the primary investment.

Notes receivable: Notes receivable includes loans made to customers for the purchase of energy efficient appliances, which are generally the security for the loan. The loans have terms ranging from one to ten years at interest rates varying from 6.5% to 12%.

Cash and cash equivalents: For purposes of reporting cash flows, the Company accounts for all liquid investments, with a purchased maturity of three months or less, as cash equivalents. The following provides additional information to the Consolidated Statements of Cash Flows:

(Dollars in thousands)	2003	2002	2001
Changes in current assets and current liabilities:			
Accounts and notes receivable	$ 2,327	$ 4,318	$ 2,208
Income taxes	1,156	(4,031)	936
Inventories	(180)	(5,686)	(2,632)
Prepaid expenses and other assets	108	12	(363)
Accounts payable and accrued expenses	(7,192)	4,647	(847)
Other	(1)		427
Net change in current assets and current liabilities	$ (3,782)	$ (740)	$ (271)
Cash payments:			
Interest (net of amounts capitalized)	$ 12,288	$ 11,074	$ 10,868
Income taxes	$	$ 6,938	$ 6,911

Materials, supplies and inventories: Materials and supplies for construction, operations, and maintenance, and inventories of natural gas are recorded at cost.

Regulatory accounts: The Company s financial statements are prepared in accordance with Statement of Financial Accounting Standards (FAS) No. 71, Accounting for the Effects of Certain Types of Regulation . This statement provides for the deferral of certain costs and benefits that would otherwise be recognized in revenue or expense, if it is probable that future rates will result in recovery from customers or refund to customers of such amounts.

Regulatory assets (liabilities) at September 30, 2003 and 2002 include the following:

(dollars in thousands)	2003	2002

Unamortized loss on reacquired debt	$	2,379	$	2,908
Gas cost changes		11,584		18,788
Deferred income taxes		(3,967)		(4,138)
Postretirement benefits other than pensions				187
Other, net		(432)		(438)
Net	$	9,564	$	17,307

Revenue recognition: The Company recognizes operating revenues based on deliveries of gas to customers. This includes estimated revenues for gas delivered but not billed to residential and commercial customers from the latest meter reading date to the end of the accounting period.

Leases: The Company leases a majority of its vehicle fleet. These leases are classified as operating leases. The Company s primary obligation under these leases is for a twelve-month period, with options to extend the lease thereafter. Commitments beyond one year are not material. Rent expense under operating leases totaled $836,000, $813,000, and $980,000 for fiscal years ended September 30, 2003, 2002, and 2001, respectively.

Federal income taxes: The Company normalizes temporary differences between book income and taxable income, with the exception of depreciation differences on assets placed in service prior to 1981, consistent with the policies of the WUTC and OPUC. Deferred income taxes are determined using the asset and liability method, under which deferred tax assets and liabilities are measured based upon the temporary differences between the financial statement and income tax bases of assets and liabilities, using current tax rates.

Investment tax credits: Investment tax credits were deferred and are amortized over the remaining life of the properties that gave rise to the credits.

Use of estimates: The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from these estimates. The Company has used estimates in measuring certain deferred charges and deferred credits related to items subject to approval of the WUTC and the OPUC. Estimates are also used in the development of discount rates and trend rates related to the measurement of retirement benefit obligations and accrual amounts, allowances for doubtful accounts, and in the determination of depreciable lives of utility plant.

Stock-Based Compensation: Compensation cost for stock options is measured as the excess of the market price of the Company s stock at the date of the grant over the price the employee must pay to acquire the stock. The Company accounts for its stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees rather than using the fair-value-based method prescribed under FAS No. 123, Accounting for Stock-Based Compensation. The Company has adopted the disclosure requirements of FAS No. 123. See Note 6 for more information about the Company s stock-based compensation plan. Had compensation expense been determined in accordance with FAS 123, the Company s net income would have been as follows:

	2003	2002	2001
	(in thousands except per-share data)		
Amounts as reported, reflecting stock-based employee compensation cost determined under APB No. 25:			
Stock-based employee compensation cost, net of tax effect	$	$	$
Net income (loss)	$ 9,104	$ 10,762	$ 17,236
Basic earnings (loss) per share	$ 0.82	$ 0.97	$ 1.56
Diluted earnings (loss) per share	$ 0.82	$ 0.97	$ 1.56
Proforma amounts, reflecting stock-based employee compensation cost as if determined under fair value (FAS 123) method:			

Stock-based employee compensation cost, net of tax effect	$	110	$	129	$	133
Net income (loss)	$	8,994	$	10,633	$	17,103
Basic earnings (loss) per share	$	0.81	$	0.96	$	1.55
Diluted earnings (loss) per share	$	0.81	$	0.96	$	1.55

Comprehensive Income (Loss): Comprehensive income for the fiscal years ended September 30, 2003, 2002 and 2001, included charges to Other Comprehensive Income in the amount of $1,682,000, $7,587,000 and $4,161,000, net of income tax. The charges are related to minimum pension liability adjustments. See Note 10 for more information.

Segment Reporting: Management views the Company as operating as a single segment, that of a local distribution company in the Pacific Northwest. Therefore, the financial statements do not include disclosure of segment information.

Derivatives: The Company records derivative transactions according to the provisions of FAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* , as amended by FAS No. 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities* , and by FAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* . These standards require that the fair value of all derivative financial instruments be recognized as either assets or liabilities on the Company s balance sheet. Changes during a period in the fair value of a derivative instrument are required to be included in earnings or other comprehensive income for the period.

The Company s contracts for purchase and sale of natural gas qualify for the normal purchase and normal sales exceptions under FAS No. 133. Accordingly, the Company recognizes revenues and expenses on an accrual basis, based on physical delivery of natural gas. The Company applies mark-to-market accounting to financial derivative arrangements. Periodic changes in fair market value are recognized in earnings.

New Accounting Standards:

Effective October 1, 2002, the Company adopted accounting standards prescribed under FAS Nos. 142, 143, 144, and 145, the effects of which are described in the following paragraphs.

FAS No. 142, *Goodwill and Other Intangible Assets.* This standard addresses how intangible assets that are acquired individually or with a group of other assets should be accounted for in financial statements upon their acquisition. This Statement also addresses how goodwill and other intangible assets should be accounted for after they have been initially recognized in the financial statements. Adoption of this standard did not have an impact on the Company s financial statements.

FAS No. 143, *Accounting for Asset Retirement Obligations.* This standard requires companies to record a liability to recognize future obligations to remove assets. The Company has reviewed its franchises and significant easements and other documents to determine whether any include provisions requiring removal of assets. No significant obligations have been identified, and adoption of this standard did not have an impact on the Company s financial statements.

FAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets.* This standard provides for the recognition and measurement of an impairment loss if it is determined the carrying amount of a long-lived asset is not recoverable, and exceeds its fair value. It also identifies events or changes in circumstances that would require a test for recoverability. Adoption of this standard did not have an impact on the Company s financial statements.

FAS No. 145, *Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections.* Adoption of this standard did not have an impact on the Company s financial statements.

In 2003, the Company has also adopted FAS Nos. 146, 148, 149, and 150, and FASB Interpretation Nos. 45 and 46, as follows:

The Financial Accounting Standards Board (FASB) has issued FAS No. 146, titled *Accounting for Costs Associated with Exit or Disposal Activities.* This standard is effective for exit or disposal activities initiated after December 31, 2002, and has been adopted by the Company effective January 1, 2003. Adoption of this standard did not have an impact on the Company s financial statements.

On December 31, 2002, the FASB issued FAS No. 148, *Accounting for Stock-Based Compensation Transition and Disclosure* . This Statement amends FAS No. 123, to provide alternative methods of transition for companies that voluntarily change to the fair-value-based method of accounting for stock-based employee compensation. In addition, this Statement amends the disclosure requirements of Statement 123 to require prominent disclosures in both annual and interim financial statements about the

method of accounting for stock-based employee compensation and the effect of the method used on reported results.

In November 2002, the FASB issued Interpretation 45, *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* . The Interpretation elaborates on the existing disclosure requirements for most guarantees, including loan guarantees such as standby letters of credit. It also clarifies that at the time a company issues a guarantee, the company must recognize an initial liability for the fair value, or market value, of the obligations it assumes under the guarantee and must disclose that information in its interim and annual financial statements. The provisions related to recognizing a liability at inception of the guarantee for the fair value of the guarantor s obligations does not apply to product warranties or to guarantees accounted for as derivatives. The initial recognition and initial measurement provisions apply on a prospective basis to guarantees issued or modified after December 31, 2002. Adoption of this standard as of January 1, 2003 did not have an impact on the Company s financial statements.

In January 2003, the FASB issued Interpretation 46, *Consolidation of Variable Interest Entities* . The Interpretation addresses consolidation by business enterprises of variable interest entities which have one or both of the following characteristics:

1) The equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support from other parties, which is provided through other interests that will absorb some or all of the expected losses of the entity.

2) The equity investors lack one or more of the following essential characteristics of a controlling financial interest:

a. The direct or indirect ability to make decisions about the entity s activities through voting rights or similar rights

b. The obligation to absorb the expected losses of the entity if they occur, which makes it possible for the entity to finance its activities

c. The right to receive the expected residual returns of the entity if they occur, which is the compensation for the risk of absorbing the expected losses.

Adoption of Interpretation 46 as of February 1, 2003 did not have an impact on the Company s financial statements.

FAS No. 149. In April 2003 the FASB issued FAS No. 149, entitled *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* . This Statement amends and clarifies financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts (collectively referred to as derivatives) and for hedging activities under FAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* , and is effective for contracts entered into or modified after June 30, 2003. Adoption of this standard did not have an impact on the Company s financial statements.

FAS No. 150. In May 2003, the FASB issued FAS No. 150, entitled *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* . This statement is effective for financial instruments entered into or modified after May 31, 2003, and is otherwise effective at the beginning of the first interim period beginning after June 15, 2003. The Company has no financial instruments affected by FAS No. 150; therefore, adoption by the Company as of July 1, 2003 did not impact the Company s financial statements.

Note 3 Earnings per Share

The following table sets forth the calculation of earnings per share as prescribed in FAS No. 128.

	2003	2002	2001
	(in thousands except per share data)		
Net Income	$ 9,104	$ 10,762	$ 17,236
Weighted average shares outstanding	11,075	11,045	11,045
Plus: Issued on assumed exercise of stock options	16	19	22
Weighted average shares outstanding assuming dilution	11,091	11,064	11,067
Earnings per common share, basic	$ 0.82	$ 0.97	$ 1.56
Earnings per common share, diluted	$ 0.82	$ 0.97	$ 1.56

The only dilutive securities are the stock options described in Note 6.

Note 4 - Utility Plant

Utility plant at September 30, 2003 and 2002 consists of the following components:

(dollars in thousands)	2003	2002
Distribution plant	$ 470,550	$ 449,430
Transmission plant	14,693	14,693
General plant	40,345	36,784
Intangible plant	212	212
Nondepreciable plant	4,007	4,007
	$ 529,807	$ 505,126

Note 5 - Common Stock

At September 30, 2003, shares of common stock are reserved for issuance as follows:

	Number of shares
Employee Savings Plan and Retirement Trust (401(k) plan)	103,026
Dividend Reinvestment Plan	
Director Stock Award Plan	1,112
Stock Incentive Plan (Note 6)	420,362
	524,500

The price of shares issued to the above plans is determined by the market price of shares on the day of, or immediately preceding the issuance date.

Note 6 Stock Compensation Plan

Under the Company s stock incentive plan, officers and other key management employees may be granted options to purchase stock. The grants vest 1/3 per year over three years. Options granted in 1999, 2000, and 2001 expire five years after the grant date. Options granted in 2002 expire ten years from the grant date. No options were granted in 2003. The weighted average remaining life of options outstanding at September 30, 2003 is 2.16 years.

The following table summarizes the grants under option at September 30:

	2003		2002		2001	
	Wtd. Avg. Exercise Price	No. Shares Under Option	Wtd. Avg. Exercise Price	No. Shares Under Option	Wtd. Avg. Exercise Price	No. Shares Under Option
Balance at October 1	$ 16.81	192,430	$ 16.81	142,966	$ 15.90	90,100
Options granted	N/A		$ 20.84	63,000	$ 18.57	58,900
Options cancelled		(3,600)		(7,166)		
Options exercised		(6,800)	$ 16.62	(6,370)	$ 15.63	(6,034)
Balance at September 30	$ 18.04	182,030	$ 18.04	192,430	$ 16.81	142,966
Exercisable at September 30	$ 17.24	124,753	$ 16.39	79,989	$ 15.86	43,033
Weighted average fair value of options granted during the fiscal year	N/A		$ 2.51		$ 2.90	

The fair value was estimated at the date of the grants using a Black-Scholes option pricing model using the following assumptions:

	Options Granted During	
	2002	2001
Dividend yield	4.61%	4.79%
Expected volatility	17%	24%
Expected life	7.5 years	5 years
Risk-Free interest rate	4.09%	4.12%

Note 7 - Notes Payable and Commercial Paper

The Company s short-term borrowing needs are met with a $50,000,000 revolving credit agreement with one of its banks. This agreement has a 0.16% annual commitment fee and a term that expires in November 2004. The Company also has a $10,000,000 uncommitted bank credit line.

September 30

(dollars in thousands)	2003	2002	2001
Amount outstanding at September 30	$ 3,800	$	$ 40,000
Average daily balance outstanding	$ 449	$ 7,973	$ 23,699
Average interest rate, excluding commitment fee	2.54%	3.01%	5.01%
Maximum month end amount outstanding	$ 6,250	$ 46,000	$ 44,500

Various debt and credit agreements restrict the Company and its subsidiaries as to indebtedness, payment of cash dividends on common stock, and other matters. Under the most conservative restriction, approximately $12,946,000 is available for payment of dividends as of September 30, 2003.

Note 8 - Long-Term Debt

Long-term debt and current maturities of long-term debt at September 30, 2003 and 2002 consists of the following:

(dollars in thousands)	2003	2002
Medium-term notes:		
7.32% due Aug. 2004	$	$ 22,000
7.18% due Oct. 2004	4,000	4,000
8.38% due Jan. 2005	5,000	5,000
8.35% due Jul. 2005	5,000	5,000
8.50% due Oct. 2006	8,000	8,000
8.06% due Sep. 2012	14,000	14,000
8.10% due Oct. 2012	5,000	5,000
8.11% due Oct. 2012	3,000	3,000
7.95% due Feb. 2013	4,000	4,000
8.01% due Feb. 2013	10,000	10,000
7.95% due Feb. 2013	10,000	10,000
7.48% due Sep. 2027	20,000	20,000
7.098% due Mar. 2029	15,000	15,000
7.50% Thirty-year notes due November 2031	39,930	39,930
Total long-term debt	$ 142,930	$ 164,930
Current Maturities of Long-Term Debt		
7.32% Medium-term notes due August 2004	$ 22,000	$

None of the long-term debt includes sinking fund requirements. Annual obligations for redemption of long-term debt and current maturities are as follows: $22,000,000 in fiscal year 2004, $14,000,000 in fiscal year 2005, none in fiscal year 2006, $8,000,000 in fiscal year 2007, none in fiscal year 2008, and $120,930,000 thereafter.

There are $125 million Medium-Term Notes (MTN s), including current maturities, outstanding as of September 30, 2003. The $39,930,000 Thirty-Year Notes were issued under a 2001 shelf registration providing ability to issue up to $150 million long-term debt and equity securities.

Note 9 - Income Taxes

The provision for income tax expense consists of the following:

(dollars in thousands)	2003	2002	2001

Current tax expense	$ 270	$ 2,850	$ 7,875
Deferred tax expense	4,652	3,137	1,606
Amortization of deferred investment tax credits	(189)	(206)	(203)
Total income tax expense	$ 4,733	$ 5,781	$ 9,278

A deferred income tax benefit associated with a charge related to accrual of minimum pension liability is included in Other Comprehensive Income (OCI) for each year ended September 30, as follows: $937,000 in 2003, $4,205,000 in 2002, and $2,341,000 in 2001. See Note 10 for more information on OCI.

A reconciliation between income taxes calculated at the statutory federal tax rate and income taxes reflected in the financial statements is as follows:

(dollars in thousands)	2003	2002	2001
Statutory federal income tax rate	35%	35%	35%
Income tax calculated at statutory federal rate	$ 4,843	$ 5,790	$ 9,282
Increase (decrease) resulting from:			
State income tax, net of federal tax benefit	109	130	200
Non-normalized depreciation differences	305	355	343
Amortization of investment tax credits	(189)	(206)	(203)
Other	(335)	(288)	(344)
	$ 4,733	$ 5,781	$ 9,278
Effective tax rate	34.2%	34.9%	35.0%

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. There is no deferred tax provision for temporary differences related to depreciation of pre-1981 assets because with respect to those assets, there is no regulatory recognition of deferred tax accounting.

Deferred tax assets and liabilities are calculated under FAS No. 109, Accounting for Income Taxes . FAS No. 109 requires recording deferred tax balances, at the currently enacted tax rate, for all temporary differences between the book and tax bases of assets and liabilities, including temporary differences for which no deferred taxes had been previously provided because of use of flow-through tax accounting for rate-making purposes. Because of prior and expected future rate-making treatment of temporary differences for which flow-through accounting has been utilized, a regulatory liability for income taxes payable through future rates related to those temporary differences has been established. At September 30, 2003, the balance of this regulatory liability is $3,967,000.

The tax effects of significant items comprising the Company s deferred income tax accounts at September 30, 2003 and 2002 are as follows:

(dollars in thousands)	2003	2002
Current Amount:		
Deferred assets:		
Allowance for doubtful accounts	$ 365	$ 425
Accrued liabilities	360	1,148
Other	30	75
	$ 755	$ 1,648
Non-current Amounts:		
Deferred tax liabilities:		
Basis differences on net fixed assets	$ 31,854	$ 26,385

Debt refinancing costs		851		1,041
Retirement benefit obligations		941		1,360
		33,646		28,786
Deferred tax assets:				
Retirement benefit obligations		2,658		1,911
Other comprehensive income		7,484		6,532
Other		212		44
		10,354		8,487
Net non-current deferred tax liability	$	23,292	$	20,299

Note 10 - Retirement Plans

The Company has a noncontributory defined benefit pension plan that covers substantially all employees over 21 years of age with one year of service. Effective October 1, 2003 non-bargaining-unit employees will no longer accrue benefits under the plan. Benefits accrued as of that point were frozen for those employees. Employees covered by a bargaining agreement continue to accrue benefits based on a formula which includes credited years of service and the employee s annual compensation.

The Company has also provided executive officers with supplemental retirement, death, and disability benefits. This plan was also frozen September 30, 2003. Under the plan, vesting occurred on a stepped basis, with full vesting at age 55 and completing either five years of participation under the plan or seventeen years of employment with the Company, upon death, or upon a change in control. The plan supplemented the benefit received through Social Security and the defined benefit pension plan so that the total retirement benefits would be equal to 70% of the executive s highest salary during any of the five years preceding retirement. The plan also provides a death benefit equivalent to ten years of vested benefits.

The Company has an Employee Savings Plan and Retirement Trust (401(k) plan). All employees 21 years of age or older with one full year of service are eligible to enroll in the plan. Under the terms of the plan, the Company matches contributions based on a percentage of each employee s contribution up to 6% of the employee s compensation, as defined. Effective July 1, 2003, the Company s matching contribution percentage was reduced from 75% to 50% with respect to non-bargaining-unit employees. The rate remains at 75% for bargaining-unit employees. The Company recognized costs for contributions to this plan of $782,000, $755,000, and $842,000, for 2003, 2002 and 2001, respectively.

As part of a comprehensive review of its employee benefits plan, in the third quarter of fiscal 2003, the Company announced changes in its retirement plans for non-bargaining unit employees. Subsequent benefits will be in the form of contributions to the existing 401(k) Plan. In addition to the existing match for employee contributions the Company will contribute 4% of eligible salaries, and a 1% to 4% transition contribution, to employee retirement accounts. Additionally there will be annually determined profit-sharing contributions based on the Company achieving established targets. The retirement plans remain unchanged for bargaining-unit employees until the existing agreement expires in 2006.

The Company s health care plan provides Postretirement Benefits Other than Pensions (PBOP), consisting of medical and prescription drug benefits, to its retired employees hired prior to June 1, 1992, and their eligible dependents. Changes to this plan, announced in 2003, provide for the addition of participant contributions beginning January 1, 2004.

The revisions to the defined benefit plans constitute plan curtailments under FAS No. 88, *Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits.* Therefore the Company recorded a charge to operating expense of $1,451,000 in the third quarter as a curtailment loss associated with unrecognized prior service cost and transition obligation.

With the announcement of these plan changes, the Company s obligation and fiscal 2003 expense under these plans was re-measured as of May 1, 2003. Re-measured benefits expense for fiscal 2003, excluding the above-mentioned curtailment loss, decreased $898,000 compared to previously measured 2003 expense. Reflected in the re-measured expense is a reduction in the discount rate assumption, from 6.75% at October 1, 2002, to 6.25% at May 1, 2003.

The following tables set forth the pension and health care plan disclosures:

Components of net periodic benefit cost

	Pension Benefits			Other Benefits		
	2003	2002	2001	2003	2002	2001
Service cost	$ 1,522	$ 1,569	$ 1,928	$ 534	$ 522	$ 484
Interest cost	3,745	3,630	3,373	2,182	2,153	1,949
Expected return on plan assets	(3,738)	(3,927)	(4,171)	(731)	(721)	(903)
Amortization of transition obligation	58	100	100	657	657	657
Amortization of prior service cost	365	499	500	(375)	(72)	
Recognized net actuarial loss / (gain)	1,160	24		1,205	298	(124)
Net periodic benefit cost	$ 3,112	$ 1,895	$ 1,730	$ 3,472	$ 2,837	$ 2,063
Curtailment loss recognized	1,451					
Total benefit cost	$ 4,563	$ 1,895	$ 1,730	$ 3,472	$ 2,837	$ 2,063

	Pension Benefits		Other Benefits	
(dollars in thousands)	2003	2002	2003	2002
Change in benefit obligations				
Projected benefit obligation at beginning of year	$ 56,885	$ 49,400	$ 35,820	$ 29,266
Service Cost	1,522	1,569	534	522
Interest Cost	3,745	3,630	2,182	2,153
Plan participants contributions				
Amendments			(14,742)	
Curtailments	(2,566)			
Benefits paid	(2,397)	(2,222)	(1,130)	(1,339)
Changes in assumptions	5,955	3,568		
Actuarial (gain)/loss	227	940	2,347	5,218
Projected benefit obligation at end of year	$ 63,371	$ 56,885	$ 25,011	$ 35,820
Change in Plan Assets				
Fair value of plan assets at beginning of year	$ 37,898	$ 40,566	$ 9,245	$ 8,695
Actual return on plan assets	5,953	(4,858)	1,428	(696)
Employer contributions	4,269	4,412	840	2,584
Plan participants contributions				
Benefits Paid	(2,397)	(2,222)	(1,130)	(1,338)
Fair value of plan assets at end of year	$ 45,723	$ 37,898	$ 10,383	$ 9,245
Funded Status	$ (17,648)	$ (18,987)	$ (14,628)	$ (26,575)
Unrecognized prior service cost	1,056	2,505	(15,121)	(755)
Unrecognized net (gain)/loss	24,940	24,698	16,745	16,300
Unrecognized transition obligation/(asset)		426	6,077	6,734
Net amount recognized	$ 8,348	$ 8,642	$ (6,927)	$ (4,296)

Amounts recognized in the balance sheet consist of:				
Prepaid pension cost	$ 3,120	$ 3,276	$	$
Accrued pension (liability)	(16,743)	(15,526)	(6,927)	(4,296)
Intangible asset	1,056	2,598		
Accumulated other comprehensive (income) loss	20,914	18,294		
Net amount recognized	$ 8,347	$ 8,642	$ (6,927)	$ (4,296)

The Company s accrued liability for pension and other postretirement benefits is included on the balance sheet in other non-current liabilities.

Weighted Average Assumptions	2003	2002
Discount rate	6.00%	6.75%
Average compensation increase	3.50%	3.50%
Expected rate of return on plan assets		
Pension plan	8.25%	8.25%
Supplemental executive retirement plan	8.25%	8.25%
Postretirement medical benefit plan	8.25%	8.25%

The assumed health care cost trend rate used in measuring the APBO at September 30, 2003 for medical costs is 8.0% for fiscal 2003, trending down to 5.5% in 2007. For prescription drug costs, the rate is 13.0% for 2003, trending down to 5.5% in 2013. A one percent change in the assumed health care cost trend rate would have the following effects as of September 30, 2003:

	One Percentage Point	
	Increase	Decrease
	(thousands)	
Effect on service and interest cost for year ended September 30, 2003	$ 537	$ (435)
Effect on accumulated postretirement benefit obligation as of 10/1/2002	$ 5,490	$ (4,521)
Effect on accumulated postretirement benefit obligation as of 9/30/2003	$ 3,141	$ (2,624)

During fiscal years 2001 and 2002, the value of the pension plan assets declined, reflecting the general downward trend in common stock values. Asset values recovered somewhat in 2003. The 2001 and 2002 declines in asset values, along with a decrease in the assumed discount rate to 6% in 2003 from 7.50% in 2001, and a reduction in the earnings assumption rate to 8.25% in 2002 and 2003 from the 9.0% 2001 rate, resulted in an unfunded accumulated benefit obligation. To recognize this liability, the Company recorded a minimum pension liability adjustment of $9,647,000 in 2001, $11,875,000 in 2002, and $2,619,000 in 2003, in accordance with the provisions of FAS No. 87.

Note 11 - Commitments and Contingencies

Gas Service Contracts

The Company has entered into various long-term contracts for natural gas supply, transportation, storage, and peaking services. These contracts are intended to provide adequate supplies of gas firm service to core customers and to meet obligations under long-term non-core customer agreements, and to provide that adequate capacity is available on interstate pipelines for the delivery of these supplies. These contracts have maturities ranging up to 25 years, and generally provide for monthly and annual fixed demand charges and minimum purchase obligations.

The Company s minimum obligations under these contracts are set forth in the following table. The amounts are based on current contract price terms and estimated commodity prices, which are subject to change:

Fiscal Year Ending September 30	Firm Gas Supply	Interstate Pipeline Transportation	Storage and Peaking Service	Total
	(dollars in thousands)			
2004	$ 155,808	$ 27,666	$ 1,870	$ 185,344
2005	29,211	27,666	1,491	58,368
2006	24,966	27,666	1,491	54,123
2007	24,966	27,666	1,491	54,123
2008	24,966	27,620	1,491	54,077
Thereafter	24,966	198,704	9,072	232,742
	$ 284,883	$ 336,988	$ 16,906	$ 638,777

Purchases under these contracts for fiscal 2003, 2002, and 2001 have been as follows:

(dollars in thousands)	Firm Gas Supply	Interstate Pipeline Transportation	Storage and Peaking Service	Total
2003	$ 159,028	$ 26,450	$ 2,140	$ 187,618
2002	$ 141,093	$ 25,210	$ 2,140	$ 168,443
2001	$ 166,912	$ 35,276	$ 3,030	$ 205,218

Financial Derivatives

To support new, fixed-price contracts for firm delivery of natural gas to a group of industrial customers in fiscal 2004, the Company entered into a swap and cap agreement in the fourth quarter of fiscal 2003. Under the terms of the swap arrangement the Company will either pay or receive settlement payments based on the difference between a fixed strike price and the monthly Inside FERC Index price. The total quantity subject to this arrangement is 1,260,000 MMBTU s in 2004 and 133,000 MMBTU s in 2005. As of September 30, 2003, the market value of this swap is a liability of $268,000, included in other non-current liabilities. The cap arrangement provides a cap on 140,000 MMBTU s in 2004 and 15,000 MMBTU s in 2005. As of September 30, 2003, the market value of this cap is $79,000, included in Other assets.

Mark-to-market adjustments on the swap and cap resulted in a $315,000 charge to earnings in the fourth quarter of 2003.

Environmental Matters

There are two claims against the Company for as yet unknown costs for clean up of alleged environmental contamination related to manufactured gas plant sites that were previously operated by companies, which were subsequently merged into Cascade.

The first claim was received in 1995, and relates to a site in Oregon. An investigation has shown that contamination does exist, but there is currently not enough information available to estimate the potential liability associated with this claim. It is expected that other parties will participate in the clean up costs. Through the end of the fiscal year the amounts spent, primarily on investigation and containment, have been immaterial.

The second claim was received in 1997, and relates to a site in Washington. An investigation has determined there is evidence of contamination at the site, but there is also evidence of an oil line crossing the property, operated by an unrelated party, which may have also contributed to the contamination. There is currently not enough information available to estimate the potential liability associated with this claim. The party who originally made this claim has not been actively pursuing it.

Management intends to pursue reimbursement from its insurance carriers, and recovery from its customers through increased rates, for any remediation costs for which the Company is determined to be liable. There is precedent for such recovery through increased rates, as both the WUTC and OPUC have previously allowed regulated utilities to increase customer rates to recover similar costs. No claims now pending, in the opinion of management, are expected to have a material effect on the Company s financial position, results of operations, or liquidity.

Litigation and Other Contingencies

Various lawsuits, claims, and contingent liabilities may arise from time to time from the conduct of the Company s business.

In the fourth quarter of fiscal 2002 a fatal accident occurred involving facilities owned by the Company, located on the property of one of the Company s commercial customers. In fiscal 2003 a settlement of all

plaintiffs claims was agreed to in consideration of a $750,000 payment. The Company and its co-defendant have each paid $375,000, and have agreed to resolve the allocation of the total settlement payment between them in future negotiations or proceedings.

No other claims now pending, in the opinion of management, are expected to have a material effect on the Company s financial position, results of operations, or liquidity.

Note 12 - Fair Value of Financial Instruments

The following estimated fair value amounts have been determined by the Company, using available market information and appropriate valuation methodologies. However, considerable judgment is required in interpreting market data to develop the estimates of fair value. Accordingly, these estimates are not necessarily indicative of the amounts that the Company could realize in a current market exchange. Thus, the use of different market assumptions or estimation methodologies may have a material effect on the estimated fair value amounts. The estimated fair values have been determined by using interest rates that are currently available to the Company for issuance of instruments with similar terms and remaining maturities. The estimated fair value amounts, at September 30, 2003 and 2002, of financial instruments whose values are sensitive to market conditions are set forth in the following table:

	2003		2002	
(dollars in thousands)	**Carrying Amount**	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Long-term debt	$ 142,930	$ 166,137	$ 164,930	$ 191,231
Current maturities of long-term debt	$ 22,000	$ 22,955	$	$

Note 13 - Interim Results of Operations (unaudited)

(thousands except per share data)	Quarter Ended 9/30/2003	6/30/2003	3/31/2003	12/31/2002
Operating revenues	$ 39,180	$ 53,793	$ 109,286	$ 100,496
Gas costs and revenue taxes	24,989	36,465	79,639	70,987
Operating margin	14,191	17,328	29,647	29,509
Cost of operations	15,597	17,249	15,749	15,789
Income (loss) from operations	(1,406)	79	13,898	13,720
Interest and other, net	2,946	3,197	3,112	3,199
Income (loss) before income taxes	(4,352)	(3,118)	10,786	10,521
Income taxes	(1,906)	(1,138)	3,937	3,840
Net income (loss)	$ (2,446)	$ (1,980)	$ 6,849	$ 6,681
Other comprehensive income (loss)	(1,682)			
Comprehensive Income (loss)	$ (4,128)	$ (1,980)	$ 6,849	$ 6,681
Earnings (loss) per common share				
Basic	$ (0.22)	$ (0.18)	$ 0.62	$ 0.61
Diluted	$ (0.22)	$ (0.18)	$ 0.62	$ 0.60

	Quarter Ended 9/30/2002	6/30/2002	3/31/2002	12/31/2001
Operating revenues	$ 39,041	$ 56,815	$ 122,361	$ 102,761
Gas costs and revenue taxes	24,891	42,562	88,905	74,118
Operating margin	14,150	14,253	33,456	28,643
Cost of operations	15,256	14,890	15,282	15,911
Income (loss) from operations	(1,106)	(637)	18,174	12,732
Interest and other, net	3,248	3,224	3,247	2,901
Income (loss) before income taxes	(4,354)	(3,861)	14,927	9,831
Income taxes	(1,846)	(1,409)	5,448	3,588
Net income (loss)	$ (2,508)	$ (2,452)	$ 9,479	$ 6,243
Other comprehensive income (loss)	(7,587)			
Comprehensive Income (loss)	$ (10,095)	$ (2,452)	$ 9,479	$ 6,243
Earnings (loss) per common share				
Basic	$ (0.23)	$ (0.22)	$ 0.86	$ 0.57
Diluted	$ (0.23)	$ (0.22)	$ 0.86	$ 0.56

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A Controls and Procedures

The Company maintains controls and procedures designed to ensure that required disclosure information in the reports the Company files or submits under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time period specified in the rules and forms of the Securities and Exchange Commission. Based upon their evaluation of those controls and procedures as of the end of the year covered by this report, the Chief Executive Officer and Chief Financial Officer of the Company concluded that the Company s disclosure controls and procedures were effective.

The Company made no significant changes in its internal controls or in other factors that could significantly affect those controls during the year covered by this report or subsequent to the date of the evaluation of those controls by the Chief Executive Officer and Chief Financial Officer.

PART III

Item 10. Directors and Executive Officers of the Registrant

Reference is made to the information regarding directors under the caption Election of Directors on pages 1 through 3 and the caption Section 16(a) Beneficial Ownership Reporting Compliance on page 7 of the Proxy Statement sent to shareholders for the 2004 Annual Meeting (the 2004 Proxy Statement), which information is incorporated herein by reference. Certain information concerning the executive officers of the Company is set forth in Part I, under the caption Executive Officers of the Registrant.

The Registrant has adopted codes of ethics for directors, officers (including the principal executive officer, principal financial officer and principal accounting officer), and employees. These codes of ethics are available on the Registrant s website at www.cngc.com.

Item 11. Executive Compensation

Reference is made to the information regarding executive compensation set forth in the 2004 Proxy Statement under Executive Compensation on pages 11 through 12, Retirement Plan on page 12, Executive Supplemental Retirement Income Plan on pages 12 and 13, Employment Agreements on pages 13 and 14, Supplemental Benefit Trust on page 14, Director Compensation on page 14, and under Compensation Committee Interlocks and Insider Participation on page 15, which information is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Reference is made to the information regarding security ownership of certain beneficial owners and management under the caption Security Ownership of Certain Beneficial Owners and Management on page 7 of the 2004 Proxy Statement (excluding the information under the subheading Section 16(a) Beneficial Ownership Reporting Compliance), which information is incorporated herein by reference.

The following table sets forth information as of September 30, 2003 with respect to compensation plans (including individual compensation arrangements) under which equity securities of the registrant are authorized for issuance:

Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights (a)		Weighted-average exercise price of outstanding options, warrants and rights (b)	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) (c)
Equity compensation plans approved by security holders	182,030	$	18.04	238,332
Equity compensation plans not approved by security holders	None		None	1,112 (Note)
Total	182,030	$	18.04	239,444

(Note) Shares available for issuance under the Registrant s 2000 Director Stock Award Plan. A proposal to increase the number of authorized shares under the 2000 Director Stock Award Plan by 35,000 shares will be considered at the Registrant s 2004 Annual Meeting of Shareholders. Reference is made to the information under the caption APPROVAL OF PROPOSAL TO INCREASE SHARES AUTHORIZED FOR ISSUANCE UNDER THE DIRECTOR STOCK AWARD PLAN on page 4 of the 2004 Proxy Statement, which information is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions

Reference is made to the information regarding certain relationships and transactions under the caption Compensation Committee Interlocks and Insider Participation on page 15 of the 2004 Proxy Statement, which information is incorporated herein by reference.

Item 14: Principal Accountant Fees and Services

Reference is made to the information regarding fees paid to, and services provided by the registrant s principal accountant under the caption Independent Public Auditors on pages 15 and 16 of the 2004 Proxy Statement, which information is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(a) 1.Financial Statements:

Consolidated Statements of Income and Comprehensive Income

Consolidated Balance Sheets

Consolidated Statements of Common Shareholders Equity

Consolidated Statements of Cash Flows

Notes to Consolidated Financial Statements

2. Financial Statement Schedule

SCHEDULE II

CASCADE NATURAL GAS CORPORATION

VALUATION AND QUALIFYING ACCOUNTS

(Thousands of Dollars)

Column A	Column B	Column C Additions		Column D	Column E
Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions (Note)	Balance at End of Period
Allowance for Doubtful Accounts:					
Year ended:					
September 30, 2001	$ 707	713		516	$ 904
September 30, 2002	$ 904	1,250		1,028	$ 1,126
September 30, 2003	$ 1,126	701		950	$ 877
Reserve - Notes Receivable					
September 30, 2001	$ 639	4			$ 643
September 30, 2002	$ 643	(155)		388	$ 100
September 30, 2003	$ 100	100		57	$ 143

Note: Accounts written off, net of recoveries

3. Exhibits. Reference is made to the index to exhibits following the signature page of this report. Each management contract or compensatory plan or arrangement required to be filed as an exhibit to this report is identified in the list.

(b) Reports on Form 8-K:

On July 25, 2003, the Company furnished a Report on Form 8-K dated July 18, 2003, to provide the information contained in its July 18 release of third quarter fiscal 2003 earnings.

On November 17, 2003, the Company furnished a Report on Form 8-K dated November 10, 2003, to provide the information contained in its November 10 release of fourth quarter and full fiscal year 2003 earnings.

SIGNATURES

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

CASCADE NATURAL GAS CORPORATION

December 17, 2003 Date	By	/s/ J. D. Wessling J. D. Wessling Chief Financial Officer

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

/s/ W. Brian Matsuyama W. Brian Matsuyama	President, Chief Executive Officer and Director (Principal Executive Officer)	December 17, 2003 Date
/s/ J. D. Wessling J. D. Wessling	Chief Financial Officer (Principal Financial Officer)	December 17, 2003 Date
/s/ James E. Haug James E. Haug	Controller (Principal Accounting Officer)	December 17, 2003 Date
/s/ Larry L. Pinnt Larry L. Pinnt	Chairman of the Board of Directors	December 17, 2003 Date
/s/ Pirkko H. Borland Pirkko H. Borland	Director	December 17, 2003 Date
/s/ Carl Burnham, Jr. Carl Burnham, Jr.	Director	December 17, 2003 Date
/s/ Thomas E. Cronin Thomas E. Cronin	Director	December 17, 2003 Date

/s/ David A. Ederer David A. Ederer	Director	December 17, 2003 Date
/s/ Mary E. Pugh Mary E. Pugh	Director	December 17, 2003 Date
/s/ Brooks G. Ragen Brooks G. Ragen	Director	December 17, 2003 Date
/s/ Douglas G. Thomas Douglas G. Thomas	Director	December 17, 2003 Date

INDEX TO EXHIBITS

Exhibit No	Description

3.1	Restated Articles of Incorporation of the Registrant as amended through March 28, 1996. Incorporated by reference to Exhibit 3.1 to the Registrant s current report on Form 8-K filed July 19, 1996.
3.2	Restated Bylaws of the Registrant.
4.1	Indenture dated as of August 1, 1992, between the Registrant and The Bank of New York relating to Medium-Term Notes. Incorporated by reference to Exhibit 4 to the Registrant s current report on Form 8-K dated August 12, 1992.
4.2	First Supplemental Indenture dated as of October 25, 1993, between the Registrant and The Bank of New York relating to Medium-Term Notes and the 7.5% Notes due November 15, 2031. Incorporated by reference to Exhibit 4 to the Registrant s quarterly report on Form 10-Q for the quarter ended June 30, 1993.
4.3	Intentionally omitted
4.4	Intentionally omitted
10.1	1998 Stock Incentive Plan of the Registrant.* Incorporated by reference to Exhibit 10.1 to the Registrant s Annual Report on Form 10-K for the year ended September 30, 1998.
10.2	Service Agreement (Storage Gas Service under Rate Schedule SGS-1) dated January 12, 1994, between Northwest Pipeline Corporation and the Registrant. Incorporated by reference to Exhibit 10.2 to the Registrant s Annual Report on Form 10-K for the year ended December 31, 1993 (1993 Form 10-K).
10.3	Service agreement (assigned Storage Gas Service under Rate Schedule SGS-1) dated January 12, 1994, between Northwest Pipeline Corporation and the Registrant. Incorporated by reference to Exhibit 10.3 to the Registrant s 1993 Form 10-K.
10.4	Service Agreement (Liquefaction Storage Gas Service under Rate Schedule SGS-1) dated January 12, 1994, between Northwest Pipeline Corporation and the Registrant. Incorporated by reference to Exhibit 10.4 to the Registrant s 1993 Form 10-K.
10.5	Intentionally omitted
10.6	Consent to Assignments, Dated June 1, 1997, which assigns from Westcoast Gas Services Inc. (WGSI), to Engage Energy Canada, L.P. (Engage) all the rights and obligations as specified in the contracts contained herein as Exhibit No. 10.22. Incorporated by reference to Exhibit 10.6 to the Registrant s Annual Report on Form 10-K for the year ended September 30, 1997 (1997 Form 10-K).
10.7	Intentionally omitted

10.8 Natural Gas Transaction Confirmation (GTC) dated November 21, 2001, and executed on April 3, 2002, between Engage Energy Canada, L.P., and the Registrant, covering the period November 1, 2003 to November 1, 2008. Incorporated by reference to Exhibit 10.8 to the Registrant s Annual Report on Form 10-K for the year ended September 30, 2002. A PORTION OF THIS AGREEMENT IS SUBJECT TO A REQUEST FOR CONFIDENTIAL TREATMENT.

10.9 Intentionally omitted.

10.10 Intentionally omitted.

10.11 Gas transportation agreement between Pacific Gas Transmission Company and the Registrant dated as of April 30, 1997. Incorporated by reference to Exhibit 10.11 to the Registrant s 1997 10-K.

10.12 Replacement Firm Transportation Agreement dated July 31, 1991, between Northwest Pipeline Corporation and the Registrant. Incorporated by reference to Exhibit 10(1) to the Registrant s registration statement on Form S-2, No. 33-52672 (1992 Form S-2).

10.12.1 Amendments dated August 20, 1992, November 1, 1992, October 20, 1993, and December 17, 1993, to Replacement Firm Transportation Agreement dated July 31, 1991, between Northwest Pipeline Corporation and the Registrant. Incorporated by reference to Exhibit 10.12.1 to the Registrant s 1993 Form 10-K.

10.13 Firm Transportation Service Agreement dated April 25, 1991, between Pacific Gas Transmission Company and the Registrant (1993 expansion). Incorporated by reference to Exhibit 10(m) to the 1992 Form S-2.

10.14 Firm Transportation Service Agreement dated October 27, 1993, between Pacific Gas Transmission Company and the Registrant. Incorporated by reference to Exhibit 10.14 to the Registrant s 1993 Form 10-K.

10.15 Intentionally omitted.

10.16 Natural gas purchase agreement dated April 26, 2001, between Sempra Energy and the Registrant. Incorporated by reference to Exhibit 10.16 to the Registrant s Annual Report on Form 10-K for the year ended September 30, 2001. A PORTION OF THIS AGREEMENT IS SUBJECT TO A REQUEST FOR CONFIDENTIAL TREATMENT.

10.17 Storage Agreement dated July 23, 1990, between Washington Water Power Company and the Registrant. Incorporated by reference to Exhibit 10(v) to the 1992 Form S-2.

10.17.1 Second amendment to the agreement for the release of Jackson Prairie Storage Capacity dated as of July 30, 1997, amending the Storage Agreement dated July 23, 1990, between Washington Water Power Company and the Registrant. Incorporated by reference to Exhibit 10.17.1 to the Registrant s 1997 Form 10-K.

10.18 Service Agreement (Firm Redelivery Transportation Agreement under Rate Schedule TF-2 for Cascade s SGS-1) dated January 12, 1994, between Northwest Pipeline Corporation and the Registrant. Incorporated by Reference to Exhibit 10.18 to the Registrant s Annual Report on Form 10-K for the year ended December 31, 1994 (1994 Form 10-K).

10.19 Service Agreement (Firm Redelivery Transportation Agreement under Rate Schedule TF-2 for Cascade s assignment of SGS-1 from WWP) dated January 12, 1994, between Northwest Pipeline Corporation and the Registrant. Incorporated by reference to Exhibit 10.19 to the Registrant s 1994 Form 10-K.

10.20	Service Agreement (Firm Redelivery Transportation Agreement under rate Schedule TF-2 for Cascade s LS-1) dated January 12, 1994, between Northwest Pipeline Corporation and the Registrant. Incorporated by reference to Exhibit 10.20 to the Registrant s 1994 Form 10-K.
10.21	Intentionally omitted
10.22	Amended and restated Natural Gas Sales Agreement dated August 17, 1994, between Westcoast Gas Services, Inc. and the Registrant Incorporated by reference to Exhibit 10.22 to the Registrant s 1994 Form 10-K.
10.22.1	Intentionally omitted.
10.22.2	Amendment dated February 28, 2003 to Amended and restated Natural Gas Sales Agreement dated August 17, 1994, between Engage Energy Canada L.P. and Registrant. A PORTION OF THIS AGREEMENT IS SUBJECT TO A REQUEST FOR CONFIDENTIAL TREATMENT.
10.23	Firm Transportation Service Agreement dated November 4, 1994, between Pacific Gas Transmission and the Registrant, effective November 1, 1995. Incorporated by reference to Exhibit 10.23 to the Registrant s 1994 Form 10-K.
10.24	Firm Transportation Agreement dated August 1, 1994, between Northwest Pipeline Corporation and the Registrant. Incorporated by reference to Exhibit 10.24 to the Registrant s 1994 Form 10-K.
10.25	Prearranged Permanent Capacity Release of Firm Natural Gas Transportation Agreements dated November 30, 1993 between Tenaska Gas Co., Tenaska Washington Partners, L.P. and the Registrant. Incorporated by reference to Exhibit 10.25 to the Registrant s 1994 Form 10-K.
10.26	Intentionally omitted
10.27	Intentionally omitted.
10.28	Intentionally omitted.
10.29	2000 Director Stock Award Plan of the Registrant.*
10.30	Executive Supplemental Retirement Income Plan of the Registrant and Supplemental Benefit Trust as amended and restated as of October 1, 2003,
10.31	Form of employment agreement between the Registrant and certain executive officers of the Registrant.
10.32	Intentionally omitted.
12.	Statement regarding computation of ratio of earnings to fixed charges and preferred dividend requirements.
21.	A list of the Registrant s subsidiaries is omitted because the subsidiaries considered in the aggregate as a single subsidiary do not constitute a significant subsidiary.

23. Consent of Deloitte & Touche LLP to the incorporation of their report in the Registrant s registration statements

31. Certification Accompanying Periodic Report Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

32. Certification Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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* Management contract or compensatory plan or arrangement.