CASCADE NATURAL GAS CORP
Form 10-K
December 08, 2006

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

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

For the fiscal year ended September 30, 2006

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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes o No x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No x

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No 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 a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o Accelerated filer x Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No x

As of March 31, 2006, the registrant had 11,471,273 shares of its Common Stock, $1 par value, outstanding. The aggregate market value of these shares of Common Stock (based upon the closing price of these shares on the New York Stock Exchange on that date) held by non-affiliates was $223,778,604.

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

Title: Common Stock, Par Value $1 per Share Outstanding 11,506,996 as of November 30, 2006

CASCADE NATURAL GAS CORPORATION
Annual Report to the Securities and Exchange Commission on Form 10-K
For the Fiscal Year Ended September 30, 2006

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PART I

Item 1. Business

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 70% of its residential and commercial gas distribution margins are from customers in the state of Washington.

The Company entered into a definitive merger agreement with MDU Resources Group, Inc. on July 8, 2006 to be acquired for cash consideration of $26.50 per share. The total value of the transaction, including the assumption of certain indebtedness, is approximately $475 million. The completion of the acquisition is subject to the approval of various regulatory authorities and the satisfaction of other customary closing conditions. The regulatory approvals include those from the Washington Utilities and Transportation Commission, the Oregon Public Utility Commission and certain jurisdictions under which MDU Resources utility divisions operate. Regulatory approvals are anticipated to be obtained by mid-year 2007. Pending the merger, Cascade must comply with the covenants contained in the merger agreement, but is generally continuing to operate in the ordinary course of business.

As of September 30, 2006, the Company had approximately 204,000 residential customers, 31,000 commercial customers, and 700 industrial and other larger 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 2006 accounted for approximately 26% of gas deliveries and 73% 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 warmer than normal winter season will tend to reduce gas consumption while a colder than normal winter season will have the opposite impact. Also affecting sales to core customers is the addition of more energy-efficient homes and facilities, consumer behavior driven by increases in natural gas pricing and a desire to conserve, and a recent trend to warmer winters in the Company s service areas. Together, these forces have resulted in reductions in average gas usage per customer. The Company has received approval for decoupling its margins from weather and conservation in the state of Oregon allowing for the recovery of margins based upon the authorized level. The Company has filed for a similar decoupling mechanism in conjunction with a rate case that it filed in the state of Washington in February 2006, and is awaiting the decision of the Washington Utilities and Transportation Commission.

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.

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), owned by TransCanada Pipeline (TCPL). GTN connects with the facilities of the TCPL at the international border near Kingsgate, British Columbia and extends through Washington and central Oregon into California. In addition, Cascade receives natural gas directly from Duke Energy Gas Transmission (DEGT) at the Canadian border near Sumas, Washington and also intra British Columbia at a receipt point known as Station 2 on DEGT.

Presently, baseload requirements for Cascade s core market are provided by eight major gas supply contracts with various expiration dates ranging from 2007 through 2010 and averaging 590,000 therms per day of Canadian supply and 191,000 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 with Avista Corporation, which is scheduled to terminate on April 30, 2007, 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 inject or withdraw 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 2006, Cascade also entered into a long-term storage agreement with Williams for service from Jackson Prairie to commence in 2010 primarily to replace the storage capability from the expiring contract with Avista Corporation. In November 2006, the Company entered into a Memorandum of Understanding with Williams (Northwest Pipeline) for a prearranged discounted transportation agreement for the transportation of Jackson Prairie stored gas to certain Cascade delivery points to start on November 1, 2009. In exchange for the discounted rate, the Company agreed to extend the primary terms of its existing transportation agreements with Northwest Pipeline by five years.

Cascade has several options available for the 2007-08 and 2008-09 winter periods to replace the 15,000 dekatherms per day of withdrawal capability at Jackson Prairie resulting from the expiring Avista Corporation storage contract. A complete analysis of these options will be conducted in the upcoming months in order to determine the best alternative(s) for the Company to pursue until the Jackson Prairie expansion is completed for the 2009-10 winter.

The Company enters into various seasonal and annual gas supply contracts designed to match the load requirements of its customers. Interstate pipelines provide natural gas to the Company from production areas in the Rocky Mountain States and from western Canada. Management believes gas supply resources in those areas are adequate to serve the Company s current needs and to support future growth. The wholesale price of gas in the region has increased in recent years, paralleling national trends. Additionally, a favorable differential that has historically existed between Pacific Northwest gas prices and national prices has narrowed as new pipelines have increased access to Rocky Mountain and Canadian supplies by California and mid-west markets.

To mitigate price volatility, the Company employs a gas procurement strategy for supplies for sale to core customers that involves entering into physical gas supply contracts with suppliers at published first-of-the-month index prices for up to five-year terms. To further mitigate the price volatility, these index-related supplies are hedged through the use of derivatives, primarily swaps, with financial institutions. Approximately 90% of the core market s requirement for fiscal 2007, 60% of fiscal 2008, and 30% of fiscal 2009 are secured with fixed prices as of the end of fiscal 2006.

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 based on market prices, and as a matter of practice, the Company generally enters into derivatives, generally swaps, to fix the price of future supplies. To the extent that overall demand is different from the amount of gas supply under contract and hedged, the net effective price paid by Cascade may change with respect to supplies purchased for core customers. The Company 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. These PGA s include interest compensation on any deferred collections financed by Cascade.

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. Cascade s gas supply portfolio for Oregon core customers is comprised mostly of gas supplies with commodity prices that have been fixed through derivative arrangements; therefore, management believes the risk or opportunity for the Company is not significant under the 67% / 33% sharing arrangement.

Cascade has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC. 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, as modified in the Company s decoupling proceeding, the Company is authorized to retain all of its earnings attributable to its Oregon operations up to a threshold level equal to 175 basis points above a 10.25% return on equity (ROE). Subsequent years base ROE is adjusted by 20% of the movement in the average of the annual yields, reported monthly, for five-, seven-, and ten-year US Treasury debt securities for the calendar year. It is anticipated that calendar year 2006 interest rates will result in a sharing threshold of a ROE of approximately 12.2%. 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.

Despite the fact that the Company has an earnings sharing mechanism in Oregon, the OPUC Staff has initiated an investigation into the Company s level of earnings in Oregon. In what is commonly referred to as a Show Cause proceeding, the OPUC Staff will have the burden of proof that the Company s rates are too high. The OPUC Staff will file its direct case on February 15, 2007, and the Company will file its answering case on April 16, 2007. Unlike general rate cases initiated by utility companies, there is no statutory time limit associated with this type of proceeding.

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 2004 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 20-year planning horizon. The IRP also sets forth possible core customer growth scenarios for a 20-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 includes the Company s supply side management plans regarding transportation capacity and gas supply acquisition over a 20-year period. The Company develops updates of the IRP every two years. Due to the large amount of regulatory activity this past year, the WUTC has granted the Company an extension to April 15, 2007 for filing the 2006 IRP update. The Oregon IRP update is due in August 2007. These updated documents take into account input solicited from the public, 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 ratemaking process, the Company cannot predict with certainty the extent to which the integrated resource planning process will affect its rates.

Like virtually all U.S. gas utilities, Cascade has experienced a declining trend in per-customer consumption over the last several years. Given the drivers, this trend is unlikely to reverse itself. To date, growth in the number of residential and commercial customers and earnings from other services contributed to offsetting this reduction. The Company has received approval of its Conservation Alliance Plan in the state of Oregon providing both conservation and weather normalization of margins. The Company filed for a similar plan with the state of Washington in conjunction with its February 2006 rate case filing. The Company remains optimistic that a similar plan will be approved by the WUTC in its final rate order due no later than mid-January 2007.

Pipeline Safety

Cascade is subject to both state and federal pipeline safety rules. In both Washington and Oregon, the state commissions enforce the federal rules. Both the federal and state rules are updated and amended periodically. Both state commissions routinely audit the Company. Based on recent safety audit findings, the Company believes it is in good standing with safety staff in both states and is not subject to any on-going enforcement proceedings. The Pipeline Safety Act of 2002 requires operators of gas transmission pipelines to identify lines located in High Consequence Areas (HCA s) and develop Integrity Management Programs (IMP s) to periodically inspect the integrity of the pipelines and make repairs or replacements as necessary to ensure the ongoing safety of the pipelines. The legislation requires Cascade to complete inspection of 50% of the highest risk pipelines located in its HCA s within the first five years, and the remaining covered pipelines within 10 years of the date of enactment. The Pipeline Safety Act also requires re-inspections of the covered pipelines every seven years from the date of the previous inspection for the life of the pipelines. Cascade has met all interim deadlines in The Act and is on schedule to meet remaining deadlines.

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, including substantial general rate increase requests by both Williams and GTN. The final outcome may affect prices Cascade pays; however, none would have a significant impact. Since the Company s current tariffs with 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 should not affect net income.

Curtailment Procedures

In some previous heating seasons, cold weather has required Cascade to curtail deliveries to its interruptible customers. Cascade has not curtailed any supply to firm customers, except under rarely occurring 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 1,080,000. At the end of September 2006, Cascade held the franchises necessary for the distribution of natural gas in all of the communities it serves in Washington and Oregon. Under the laws of those states, incorporated municipalities and counties may grant non-exclusive franchises 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 2008 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. Once connected, these customers rarely change from gas service. This category is our fastest growing with customer count increases of 3-5% during each of the last several years. The residential and commercial market is very weather-sensitive. See Seasonality below. In addition to the seasonal nature of usage, average consumption per customer has declined since the beginning of this decade. As mentioned earlier, the addition of more efficient homes and other buildings, replacing old appliances with more efficient units, and consumer behaviors drive this trend. Reductions are most pronounced following significant gas cost increases. Cascade s growth has contributed to offsetting these declines. As discussed under State Regulation, the Company has received approval of its Conservation Alliance Plan in the state of Oregon providing both conservation and weather normalization of margins. The Company filed for a similar plan with the state of Washington in conjunction with its February 2006 rate case filing. The Company remains optimistic that a similar plan will be approved by the WUTC in its final rate order due no later than mid-January 2007.

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 120-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 vary with the availability of hydroelectric power and the relative price of gas.

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, 2006, 71% of operating revenues and 104% of income from operations were derived from the first two quarters (October 2005 through March 2006). Because of the seasonality of space-heating reve–nues, 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 appliances that utilize natural gas more consistently year-round 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 increased significantly during 2005, they have somewhat abated toward the end of 2006. Cascade s residential and commercial rate schedules continue to maintain a price advantage over oil in its entire service territory and have an advantage over electricity in much of its territory. 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, and again in 2005, 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 cleanup 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

Driven by Cascade s high growth rate, capital expenditures are primarily used to expand the Company s distribution system to serve new customers. Investments to expand capacity and to assure a safe and reliable system require a relatively smaller portion of our overall capital spending. A one-time project, the installation of automated meter-reading capabilities system-wide, represented $16 million of our capital spending during fiscal years 2003 and 2004. Total capital expenditures for the three fiscal years ended September 30, 2006 averaged approximately $27.7 million. Capital expenditures during fiscal 2006 were approximately $16 million. Capital spending for fiscal 2007 is expected to be higher than fiscal 2006 and more in the range of $22-24 million.

Non-Utility Subsidiaries

Cascade has four non-utility subsidiaries, only two of which are actively engaged in business at present. The first active subsidiary, 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. In addition, Cascade Land Leasing receives a small amount of annual royalty on gas production in Colorado. These mineral rights were a result of historical operations the Company had in Colorado until the mid-1970 s. The second active subsidiary, CGC Resources, is 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, 2006, Cascade had 374 employees. Of the total employees, 207 are represented by the International Chemical Workers Union (ICWU). The present contract for the field operations bargaining unit negotiated last fiscal year with the union extends to April 1, 2009 and remains in force thereafter from year to year unless terminated by either party by written notice sixty days prior to the expiration date. The field operations bargaining unit has 174 of the 207 employees represented by the ICWU. Historically, the Company and the union have negotiated a new agreement to become effective as of the earliest expiration date rather than allowing the existing agreement to remain in force.

On November 23, 2005, 29 customer service representatives in the Company s Bellingham and Sunnyside call centers elected to be represented by the ICWU. The Company and the ICWU continue to negotiate toward an agreement at this time.

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 1-800-786-2528.

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.

NYSE Certification

On March 15, 2006, the Chief Executive Officer of Cascade filed a 303A.12(a) CEO Certification with the New York Stock Exchange. The CEO Certification attests that the Chief Executive Officer is not aware of any violations by the Company of NYSE Corporate Governance Listing Standards.

Item 1A. Risk Factors

Cascade s business and financial results are subject to a number of risks and uncertainties, including those set forth below and in other documents we file with the Securities and Exchange Commission. Investors should carefully consider these risk factors and should also be aware that this list is not all inclusive of existing risks. In addition, new risks may emerge at any time, and Cascade cannot predict those risks or the extent to which they may affect the Company s business or financial performance.

The rates we charge customers for gas distribution services are established by the OPUC and the WUTC. Their failure to approve rates, which provide for recovery of our costs and an adequate return on invested capital, may adversely impact our financial condition and results of operations.

The rates and terms at which we resell gas to our customers or transport gas owned by large customers from the interstate pipeline connection to our customers facilities must be approved by the WUTC or the OPUC. The rates are designed to allow us to recover costs of providing such services and to earn an adequate return on our capital investment. We expect to continue to make significant capital expenditures to expand and improve our distribution system. The failure of the WUTC or the OPUC to approve on a timely basis requested rate increases to recover increased costs or to allow an adequate return could adversely impact our financial condition and results of operations.

Higher natural gas commodity prices and fluctuations in the price of gas may adversely affect our earnings.

In recent years, natural gas commodity prices have increased dramatically due to growing demand, especially for power generation, and stagnant North American gas production. In Oregon, we have a Purchased Gas Adjustment (PGA) tariff, which provides for annual revisions in rates resulting from changes in the cost of purchased gas. The PGA tariff provides that 33 percent of any difference between actual purchased gas costs and estimated purchased gas costs incorporated into rates will be recognized as current income or expense. Accordingly, higher gas costs than those assumed in setting rates can adversely affect our results of operations.

Notwithstanding our current rate structure, higher gas costs could also result in increased pressure on the WUTC or the OPUC to seek other means to reduce rates to a level that could adversely affect our results of operations and financial condition.

Our risk management policies and hedging activities cannot eliminate the risk of commodity price movements and may expose us to additional liabilities for which rate recovery may be disallowed.

Our gas purchasing requirements expose us to risks of commodity price movements. We attempt to manage our exposure through enforcement of established risk limits and risk management procedures, including hedging activities. These risk limits and risk management procedures may not always work as planned and cannot eliminate the risks associated with gas purchasing and hedging. These practices are subject to regulatory review in setting our PGA tariffs and, if found to be imprudent, could be disallowed.

Our results of operations may be negatively affected by warmer than average weather.

A large portion of our margin is derived from sales to space heating residential and commercial customers between November 15 and May 15, otherwise known as the winter heating season. Current rates are based on an assumption of average weather. Although we have a weather normalization mechanism in effect in Oregon, approximately 76 percent of our residential and commercial customers are in Washington, where a similar mechanism is not in effect. Therefore the Oregon mechanism does not fully insulate us from utility earnings volatility due to weather. As a result, we are not fully protected against warmer than average weather, which may have an adverse affect on our results of operations.

Customers conservation efforts may have a negative impact on our revenues.

Higher gas costs and rates may result in increased conservation by customers, which can decrease sales and adversely affect results of operations. The OPUC authorized our conservation tariff, which is designed to recover lost margin due to changes in residential and commercial customers consumption patterns. The conservation tariff is intended to adjust for increases or decreases in consumption attributable to annual changes in commodity costs or periodic changes in general rates and for deviations between actual and expected usage. The failure of the OPUC to extend the conservation tariff in the future could adversely affect our financial condition and results of operations. In addition, the Company filed for a similar plan with the state of Washington in conjunction with its February 2006 rate case filing. The Company remains optimistic that a similar plan will be approved by the WUTC in its final rate order due no later than mid-January 2007. However, there is no certainty of outcome at this time.

Certain of our properties and facilities may pose environmental risks requiring remediation, the cost of which could adversely affect our results of operations and financial condition.

We own, or previously owned, properties that may require environmental remediation or other action. Management has determined that there is no need to accrue any costs relating to environmental remediation. The Company s results of operations may be adversely affected to the extent that estimates of environmental remediation costs increase.

There are no assurances that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to us. Revised or additional regulations which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from insurance or customers, could have a material effect on our results of operations.

Our gas distribution business is subject to increased competition and eroding price advantage.

To the extent that competition increases, our profit margins may be negatively affected. In the residential market, we compete with suppliers of electricity, fuel oil, propane and, to a lesser extent, wood. We also compete with electricity and fuel oil for commercial applications. In the industrial market, we compete with all forms of energy. Competition among these forms of energy is based on price, reliability, efficiency and performance.

Higher natural gas prices have eroded or, in some cases, eliminated the competitive price advantage of natural gas over alternative energy sources. If the higher gas price environment is sustained, our ability to attract new customers could be significantly affected, which could have a negative impact on our customer growth rate and results of operations.

Volatility in the price of natural gas could result in large industrial customers switching to alternative energy sources and reduced revenues, earnings and cash flow.

The market price of alternative energy sources such as coal, electricity, oil and steam is the primary competitive factor affecting the demand for the Company s gas transportation services. Certain large industrial customers have, or may acquire, the capacity to be able to use one or more alternative energy sources or shift production to facilities outside the Company s service area if the price of natural gas and delivery services increases significantly. Natural gas has typically been less expensive than these alternative energy sources. However, generally over the past four years, natural gas prices have been higher and more volatile, making some of these alternative energy sources more economical or, for other reasons, more attractive than natural gas. The Company cannot predict the future stability of natural gas prices. Should these customers convert their requirements to another form of energy, the Company s revenues, earnings and cash flow would be adversely affected.

Earnings and cash flow may be adversely affected by downturns in the economy.

The Company s operations are affected by the conditions and overall strength of the national, regional and local economies, which impact the amount of residential, industrial and commercial growth and actual gas consumption in the Company s service territories. Many of the Company s commercial and industrial customers use natural gas in the production of their products. During economic downturns, these customers may see a decrease in demand for their products, which in turn may lead to a decrease in the amount of natural gas they require for production. In addition, during periods of slow or little economic growth, energy conservation efforts often increase and the amount of uncollectible customer accounts often increases. These factors could adversely affect our financial condition.

The cost of providing pension and post-retirement benefit plans is subject to changes in pension assumptions, fluctuations in the market value of plan assets and changing demographics, and may have a material effect on our financial results.

The Company maintains a qualified medical contributory defined benefit pension plan, a non-qualified supplemental pension plan and a post-retirement benefit plan. We may be required to recognize a material increase or decrease in annual pension or post-retirement benefit expense based on changes in assumed interest rates, market returns, and other factors, and we may be required to record a charge to our balance sheet to the extent that benefit obligations exceed the fair value of the plan assets.

The Company s business is dependent on its ability to successfully access capital markets.

The Company relies on access to both short-term money markets as a source of liquidity and longer-term capital markets to fund at least a portion of its utility construction program and other capital expenditure requirements not satisfied by cash flow from its operations. If the Company is unable to access capital at competitive rates, its ability to pursue growth, replacements, and improvements could be adversely affected. Certain market disruptions or a downgrade of the Company s credit rating may increase the Company s cost of borrowing or adversely affect the ability to access one or more financial markets. In addition to further economic downturns and the overall health of the utility industry, such disruptions could include:

- the bankruptcy of an unrelated energy company;
- capital market conditions generally;
- market prices for natural gas; or
- terrorist attacks or threatened attacks.

A downgrade in the Company s credit rating could negatively affect its ability to access capital.

Standard and Poor s and Moody s Investor Services rate Cascade s debt at BBB+ with a stable outlook and Baa1 with a stable outlook, respectively. Although the Company is not aware of any current plans of S&P or Moody s to lower their respective ratings on Cascade s debt, the Company cannot be assured that such credit ratings will not be downgraded. Although Cascade does not have any rating downgrade triggers that would accelerate the maturity dates of outstanding debt, a downgrade in the Company s credit ratings could adversely affect its ability to renew existing, or obtain access to new credit facilities and could increase the cost of such facilities.

Transporting natural gas involves numerous risks that may result in accidents and other operating risks and costs.

Our gas distribution activities involve a variety of inherent hazards and operating risks, such as leaks, accidents and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution and disruption of our operations, which in turn could lead to substantial losses. The occurrence of any of these events may not be covered by our insurance policies or recoverable through rates, which could adversely affect our financial condition and results of operations.

Failure to complete the planned merger with MDU Resources Group, Inc. could have a negative impact on the Company s share price.

The completion of our pending merger with MDU Resources Group, Inc. is subject to the approval by various regulatory authorities and the satisfaction of other customary closing conditions. The merger may not occur if that Company is unable to obtain necessary regulatory approvals in a timely manner, or satisfy other closing conditions. Therefore, if the merger is not concluded, Cascade s share price may be impacted.

In anticipation of the planned merger with MDU Resources Group, Inc., personnel may decide to leave the Company.

Individual employees may experience uncertainty about their post-merger roles with MDU Resources. Issues relating to the uncertainty and difficulty of integration or a desire not to remain with MDU Resources after the merger may cause them to voluntarily leave the Company for other career opportunities. Loss of significant numbers of employees, or employees in key positions, could have a detrimental impact on the Company s ability to carry on certain routine business activities. To mitigate this risk, the Company has provided Change-in-Control incentives to employees in key roles to encourage them to stay with the Company at least through the completion of the merger. However, there can be no assurance that such employees will not leave the Company, or that we will be able to find adequate replacements if they do depart.

Item 1B. Unresolved Staff Comments

As of the filing date of this report, the Company does not have any unresolved comments from the Securities and Exchange Commission staff.

Item 2. Properties

At September 30, 2006, Cascade s utility plant investments included approximately 5,408 miles of distribution mains rang–ing in diameter from two inches to sixteen inches, 214 miles of transmission mains ranging in diameter from two inches to twenty inches, and 3,681 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 two 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.

Item 3. Legal Proceedings

On July 31, 2006, a complaint was filed with the Washington Utilities and Transportation Commission (WUTC) by Cost Management Services, Inc. against the Company. The complaint contends the

Company s sales to customers under its gas management program are not allowed. The complainant is in the gas management business and is a competitor of the Company for this business with the same customers. The complaint requests that the Company be directed to cease and desist from making such sales. It further requests the WUTC determine whether the Company s contracts with its gas management customers are void or voidable under Washington statutes and to provide other relief or penalties as the WUTC may consider appropriate under the circumstances. The Company believes that its gas management business is in compliance with applicable laws.

The parties to the Complaint Docket have filed a Stipulation of Facts and have agreed to file simultaneous motions and briefs on the same dates reserved for briefs in the Washington general rate case docket. The WUTC has indicated that it will issue an order in the Complaint Docket prior to, or at the same time as, the final order in the general rate case docket.

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 2006.

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PART II

Item 5. Market for Registrant s Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities

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:

Quarter	Fiscal 2006 High	Low	Fiscal 2005 High	Low
December 31	$ 22.00	$ 19.50	$ 21.80	$ 20.00
March 31	$ 20.30	$ 18.95	$ 21.48	$ 19.68
June 30	$ 21.30	$ 19.26	$ 20.59	$ 18.05
September 30	$ 26.30	$ 20.84	$ 22.80	$ 20.01

At September 30, 2006, there were 5,148 registered holders of the Common Stock. The following table shows for the periods indicated the dividends paid per share on the Common Stock:

Quarter	Fiscal 2006	Fiscal 2005
December 31	$ 0.24	$ 0.24
March 31	$ 0.24	$ 0.24
June 30	$ 0.24	$ 0.24
September 30	$ 0.24	$ 0.24

While the Company s debt agreements do contain restrictions on the Company s ability to pay dividends in certain circumstances, at September 30, 2006, the Company was in compliance with all indebtedness covenants and was not restricted with respect to dividend payments.

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	25,000	$ 20.84	316,842
Equity compensation plans not approved by security holders	None	None	None
Total	25,000	$ 20.84	316,842

Item 6. Selected Financial Data

The following selected financial data are derived from the consolidated financial statements of the Company.

Consolidated Statements of Income and Comprehensive Income:

	Year Ended September 30				
	2006	**2005**	**2004**	**2003**	**2002**
	(dollars in thousands except per-share data)				
Operating Revenues	$ 455,964	$ 326,500	$ 318,078	$ 302,755	$ 320,978
Less: Gas Purchases	327,570	212,958	202,759	191,887	209,225
Revenue taxes	30,335	21,827	21,511	20,193	21,251
Operating Margin	98,059	91,715	93,808	90,675	90,502
Cost of Operations:					
Operating expenses	44,454	44,223	40,540	45,514	43,052
Depreciation and amortization	17,861	17,274	16,325	15,338	14,926
Property and payroll taxes	3,748	3,786	3,696	3,532	3,361
	66,063	65,283	60,561	64,384	61,339
Income From Operations	31,996	26,432	33,247	26,291	29,163
Nonoperating Expense (Income):					
Interest	11,951	11,744	12,375	12,363	12,384
Interest charged to construction	(50)	(187)	(445)	(378)	(219)
	11,901	11,557	11,930	11,985	12,165
Amortization of debt issuance expense	396	372	618	696	652
Other	(1,545)	(376)	(162)	(227)	(197)
	10,752	11,553	12,386	12,454	12,620
Income Before Income Taxes	21,244	14,879	20,861	13,837	16,543
Income Taxes	8,755	5,632	7,559	5,117	6,085
Net Income	12,489	9,247	13,302	8,720	10,458
Earnings Per Common Share, Basic and Diluted	$ 1.09	$ 0.82	$ 1.19	$ 0.79	$ 0.95

	At September 30 2006	2005	2004	2003	2002
	(dollars in thousands except per-share data)				
Retained Earnings:					
Beginning of the year	$ 15,908	$ 17,570	$ 15,051	$ 16,978	$ 17,127
Net income	12,489	9,247	13,302	8,720	10,458
Exercise of stock options					(4)
Common dividends	(11,025)	(10,909)	(10,783)	(10,647)	(10,603)
End of the year	$ 17,372	$ 15,908	$ 17,570	$ 15,051	$ 16,978
Capital Structure:					
Common shareholders equity	$ 122,127	$ 118,615	$ 117,584	$ 111,630	$ 113,635
Debt:					
Long-term debt	165,123	173,840	128,900	142,930	164,930
Short-term debt		12,500	33,500	3,800	
Current maturities of long-term debt	8,000		14,000	22,000	
	173,123	186,340	176,400	168,730	164,930
Total capital	$ 295,250	$ 304,955	$ 293,984	$ 280,360	$ 278,565
Financial Ratios:					
Return on common shareholders equity	9.86 %	7.46 %	11.03 %	7.33 %	8.27 %
Common stock dividend payout ratio	88 %	117 %	81 %	122 %	101 %
Cash dividends per common share	$ 0.96	$ 0.96	$ 0.96	$ 0.96	$ 0.96
Fixed charge coverage (before income tax deduction):					
Times interest earned	2.72	2.23	2.61	2.06	2.27
Book value per year-end share of common stock	$ 10.61	$ 10.39	$ 10.44	$ 10.03	$ 10.29
Capitalization Ratios at End of Year					
Common shareholders equity	41.4 %	38.9 %	40.0 %	39.8 %	40.8 %
Long-term debt (incl. current maturities)	58.6 %	57.0 %	48.6 %	58.8 %	59.2 %
Short-term debt	0.0 %	4.1 %	11.4 %	1.4 %	0.0 %
	100.0 %	100.0 %	100.0 %	100.0 %	100.0 %
Utility Plant:					
Utility plant end of year	$ 614,184	$ 597,469	$ 570,036	$ 529,807	$ 505,126
Accumulated depreciation	273,138	257,008	242,691	227,582	213,476
Net plant	$ 341,046	$ 340,461	$ 327,345	$ 302,225	$ 291,650
Capital expenditures, net of contributions in aid	$ 16,018	$ 28,011	$ 39,019	$ 27,693	$ 20,734
Total assets	$ 456,706	$ 552,905	$ 422,622	$ 371,456	$ 367,663
Number of Employees at End of Year	374	375	428	437	444

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

Overview

The Company is a local distribution company (LDC) serving approximately 236,000 customers in the states of Washington and Oregon. Its service area consists primarily of relatively small cities and rural communities rather than larger urban areas. The Company s primary source of revenue and operating margin is the distribution of natural gas to end-use residential, commercial, industrial, and institutional customers. Revenues are also derived from providing gas management and other services to some of its large industrial and commercial customers. The Company s rates and practices are regulated by the Washington Utilities and Transportation Commission (WUTC) and the Oregon Public Utility Commission (OPUC).

Key elements of the Company s strategy are as follows:

- Continue to efficiently and effectively operate the Company to achieve business goals and maintain full compliance with the terms of the merger agreement with MDU Resources Group, Inc.

- Remain focused on the natural gas distribution business.

- Pursue appropriate regulatory treatment, including initiatives to decouple the Company s earnings from changing customer consumption patterns, and remove other regulatory impediments to effective management of the business.

- Economic expansion of its customer base by prudently managing capital expenditures and ensuring new customers provide sufficient margins for an appropriate return on the new investment required to acquire the customers.

- Continue to focus on operational efficiencies.

- Manage cash flow to minimize the need for additional debt financing.

Opportunities and Challenges

The Company operates in a diverse service territory over a wide geographic area relative to the Company s overall size and number of customers. The economies of various parts of the service area are supported by a variety of industries and are affected by the conditions that impact those industries. Management believes there are continued growth opportunities in the Company s service area, especially in the residential and commercial segments. Factors contributing to these opportunities include general population growth in the service area, including some areas of very rapid growth, and to a lesser extent, low market penetration in many of the communities served.

Overall revenues and margins are negatively impacted by higher efficiency in new home and commercial building construction, higher efficiency in gas-burning equipment, and customers taking additional measures to reduce energy usage. The increasing cost of energy in recent years, including the wholesale cost of natural gas, continues to encourage such measures. However, the Company continues to believe that energy efficiency and conservation are the most viable near-term tactics for reducing customer bills and influencing wholesale natural gas prices. They also form a vital strategy for stabilizing the cost of gas over the long term. The traditional regulatory establishment of rate recovery tied to volumetric sales no longer seems prudent. This traditional rate design creates a financial disincentive for utilities to promote conservation. The Company has filed a rate case in the State of Washington along with a request to decouple the margin recovery from volume. The Company worked with the regulatory staff and other stakeholders in this case to develop an acceptable decoupling mechanism that will enable the Company to promote conservation while still recovering its operating costs and earning a fair return on its invested capital. Similar approaches have been implemented in many states, including Oregon (see below), and are endorsed by a variety of organizations, including the National Association of Regulatory Utility Commissions. The results of such rate requests and other initiatives for regulatory relief are subject to significant uncertainties.

In April 2006, the OPUC approved the Company s request to implement its Conservation Alliance Program, which effectively decouples operating margin from the impacts of conservation and weather on gas usage by residential and commercial customers in its Oregon service area. The filing provides a mechanism where the Company will adjust its earnings recovery to fully recover the Commission-granted level of earnings per customer. This is done via a deferral mechanism for both conservation and weather. In simple terms, the Company will book the actual earnings and a deferral for both conservation and normal weather each month. The next year, depending on the amount of conservation and level of weather, the Company will adjust its rates either downward or upward to ensure recovery at the allowed level. The Company agreed to lower its sharing mechanism cap by 125 basis points in exchange for approval of the Conservation Alliance Program. The Company expects to share earnings during this fiscal year due to this lowering of the cap.

Revenues and margins from the Company s residential and small commercial customers in Washington are highly weather-sensitive. In a cold year, the Company s earnings are boosted by the effects of the weather, and conversely in a warm year, the Company s earnings suffer. Peak requirements also drive the need to reinforce our systems (i.e., increase capacity). Our operations group considers innovative approaches such as temporarily utilizing mobile gas supply rather than making large investments in long-term capacity increases which may not be fully utilized.

Management believes that prospects for continuing strong residential and commercial customer growth are excellent. The pace of new home and commercial construction remains steady in communities served by the Company. In addition, management believes that potential for growth also exists for converting homes and businesses located on or near the Company s current lines to gas from other fuels, as well as for expanding the system into adjacent areas. Customer count growth in this sector has been more than double the average of U.S. gas utilities.

The Company earns approximately one third of its operating margin from industrial and electric generation customers. Loss of major industrial customers, or unfavorable conditions affecting an industry segment, would have a detrimental impact on the Company s earnings. Many external factors over which the Company has no control can significantly impact the amount of gas consumed by industrial and electric generation customers and, consequently, the margins earned by the Company. Such factors may include base-load electricity demand, refinery operations and electricity price in a market impacted significantly by hydroelectric generation. Additional electric generation and industrial customers may be active if there is peaking demand for electricity. Other external factors that impact different segments of the industrial market include weather, temperature, seasonality of processes, energy commodity pricing, price of natural gas supplies, profitability of industrial segments and regional economic conditions.

In November 2005, our customer service call center organization voted to accept union representation. The Company is attempting to negotiate an agreement that will support our efforts to cost-effectively provide superior customer service. The results of negotiations are uncertain.

We carefully analyze the economics of our capital spending to support growth. When justified under our tariffs, we work with developers, business owners and residents to share certain construction costs to assure a fair return to the Company. Non-revenue-generating spending is also managed to assure that we use the most economically attractive solutions while providing for a safe and reliable system. Where possible, we work with developers and customers to utilize shared trenches, significantly reducing the cost of main extensions and service connections. We also maintain the flexibility through variable overtime and the use of outside contractors to adjust our capital construction levels to each period s requirements.

Management continuously seeks improvement opportunities in all areas. Our discussion above covering regulatory change, labor relations, operating practices, our organization and our investment to maintain and expand our gas delivery system are examples. Concurrent with supporting the required activities to complete the proposed merger, management will continue these efforts to maintain and continuously improve Cascade s operational performance within the terms of the merger agreement.

RESULTS OF OPERATIONS

2006 Versus 2005

The Company reported net income for 2006 of $12,489,000, or $1.09 per share, compared to $9,247,000 or $0.82 per share for 2005. References herein to per-share earnings refer to both basic and diluted, unless otherwise indicated. Primary factors resulting in the increase in earnings per share include:

Operating Margin Factors:

- Increase in the number of residential and commercial customers $0.16 per share
- Increased natural gas usage per residential and commercial customer $0.10 per share
- Increased margin from electric generation customers $0.07 per share
- Improvements in incentive cost sharing related to gas purchases for Oregon customers $0.04 per share
- Increased miscellaneous service revenues $0.04 per share

Partially offset by:

- Unfavorable comparison of Oregon earnings sharing ($0.06) per share

Cost of Operations Factors:

- Executive and other transition costs recorded in 2005 $0.13 per share
- Reduction in 2006 employee benefits expenses $0.11 per share
- Reduction in 2006 in spending in various expense categories $0.02 per share

Offset by:

- 2006 Expenses related to pending merger ($0.15)
- Reduction in capitalization of operating expenses ($0.08) per share
- Increased bad debts expense ($0.04) per share
- Increased depreciation and amortization expense ($0.03) per share

Non-operating Expense (Income) improved $0.04 per share

Increased effective income tax rate ($0.06) per share

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2005 Versus 2004

The Company reported net income for 2005 of $9,247,000, or $0.82 per share, compared to $13,302,000 or $1.19 per share for 2004. References herein to per-share earnings refer to both basic and diluted, unless otherwise indicated. Primary factors resulting in the decrease in earnings per share include:

Operating Margin Factors:

- Reduced natural gas usage per residential and commercial customer $0.15 per share
- Lower margin from gas management services $0.11 per share
- Unfavorable comparison of mark-to-market valuations versus 2004 $0.06 per share
- Lower margins from deliveries to industrial customers $0.04 per share

Cost of Operations Factors:

- Executive transition costs associated with changes in the Chief Executive Officer and Chief Financial Officer $0.07 per share
- Severance compensation associated with staffing reductions $0.06 per share
- Increased depreciation expenses $0.05 per share
- Write-offs of cancelled projects $0.03 per share
- Increased purchased services expenses $0.03 per share
- Increased uncollectible accounts expenses $0.02 per share

The above were partially offset by the following factors:

- Increase in the number of residential and commercial customers $0.18 per share
- Revision of estimated liability for Oregon Earnings sharing $0.05 per share
- Lower employee benefits expense $0.04 per share

OPERATING MARGIN

Operating margins (revenue minus gas cost and revenue taxes) by customer category for the fiscal years ended September 30, 2006, 2005 and 2004 are set forth in the tables below:

Residential and Commercial Operating Margin

	2006	**2005**	**2004**
	(dollars in thousands)		
Degree Days	5,688	5,170	5,212
Average Number of Customers Billed			
Residential	203,881	194,469	184,845
Commercial	30,843	30,183	29,320

Average Therm Usage Per Customer			
Residential	703	683	710
Commercial	3,661	3,474	3,628
Operating Margin			
Residential	$ 45,168	$ 40,642	$ 39,691
Commercial	$ 23,835	$ 21,672	$ 22,014

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Industrial and Other Operating Margin

	2006	2005	2004
	(dollars and therms in thousands)		
Average Number of Customers Billed			
Electric Generation	11	13	14
Industrial	693	718	737
Therms Delivered			
Electric Generation	404,437	437,934	480,859
Industrial	414,363	406,218	415,740
Operating Margin			
Electric Generation	$ 9,043	$ 7,663	$ 8,013
Industrial	$ 18,741	$ 18,672	$ 19,389
Gas Management Services	$ 1,593	$ 1,432	$ 3,309
Mark-to-Market Valuations	$ (579)	$ (181)	$ 836
Other Service Revenue	$ 806	$ 1,290	$ 882
Oregon Earnings Sharing estimates	$ (548)	$ 525	$ (326)

2006 Versus 2005

Residential and Commercial *Operating* margin (revenue minus gas costs and revenue taxes) is primarily a function of customer growth and gas usage per customer. Residential and commercial margins increased by $6.6 million for the year. Customer growth at 4.5%, with the net addition of over 10,000 new customers, contributed $2.9 million to margins, while higher average consumption improved margins by $1.7 million. With cooler weather, average residential and commercial consumption increased by 2.9% and 5.4%, respectively. When measured in degree-days, this fiscal year was 10% cooler than the prior year. The difference between the consumption rates and the weather is attributed to weatherization efforts and consumer behavior encouraged by significant gas cost increases occurring nationwide early in the fiscal year. Miscellaneous services provided $796,000, and revenues recognized relating to the May 2006 implementation of weather and conservation decoupling in Oregon added $289,000. Changes relating to the treatment of Oregon gas cost differentials increased the reported margin by $879,000 when compared to fiscal 2005.

Electric Generation *Margins* from sales to electric generation plants increased by $1.4 million over 2005, primarily due to two contract settlements totaling $1 million.

Oregon Earnings Sharing *Operating* margins in 2006 reflect $548,000 in accrued Oregon Earnings Sharing reported for the fiscal year, compared to last year s reversal of $525,000 in accrued sharing. An April agreement to institute weather and conservation decoupling reduced the target rate of return for when sharing is required with our Oregon customers. Together, these adversely impacted the year-to-year comparison by $1.1 million.

2005 Versus 2004

Residential and Commercial *The* net addition of approximately 10,500 billed residential and commercial customers in 2005 contributed approximately $3,160,000 of additional margin compared to fiscal 2004. This was mostly offset by reductions in gas usage per residential and commercial customer of 3.8% and 4.4%, respectively, which reduced margins by $2,550,000. The addition of more efficient homes and businesses, reduced consumption per consumer, and slightly warmer weather compared to 2004 drove the lower consumption rates. Weather statistics indicate that fiscal 2005 was 1% warmer than fiscal 2004 and 4% warmer than the average of the previous five years.

Industrial *Margin* from natural gas deliveries to industrial customers decreased by $717,000 year to year. This reduction is due to a variety of reasons including contract changes reducing minimum requirements, a decline in the number of customers and reduced usage by several sectors including chemical and paper manufacturing.

Electric Generation *Margin* from natural gas deliveries to electric generation customers decreased $350,000 for the year with the decline attributable to lower-cost hydroelectric supplies and the increased wholesale price of natural gas. Looking ahead, gas usage by generation customers will continue to depend on the variables of regional demand for power, availability of hydro resources, and the relationship between the market price of electricity and the cost of gas.

Gas Management *Gas* management services margin was down $1,877,000 from 2004. The Company has lost sales and margin as a result of increased competition for the sale of gas supplies to large-volume customers.

Oregon Earnings Sharing *The* change in Oregon Earnings Sharing amounts are the result of revised estimates of liability for refunds to Oregon customers related to OPUC requirements. As of the end of 2004, the Company estimated its liability to be $525,000. Based on a final analysis approved by the OPUC, 2004 and 2005 earnings were not sufficient to trigger a sharing with customers, and in 2005 the $525,000 2004 estimate was reversed.

COST OF OPERATIONS

2006 Versus 2005

Full year cost of operations (operating expense, depreciation and amortization, and property and miscellaneous taxes) increased by $780,000 compared to 2005. Net of merger related costs of $2.7 million, full year cost of operations was $1.9 million lower. Favorable items include $2.4 million in transition costs recognized in fiscal 2005, a $2.0 million reduction in employee benefits costs, and another $309,000 in reduced spending across a broad range of operating costs. Offsetting these savings was a $1.5 million reduction in capitalized expenses related to management initiatives to reduce spending on capital projects. Bad debts expense increased $741,000 due to higher revenues and customer bills. Depreciation increased $587,000 reflecting higher depreciable assets resulting from capital spending.

2005 Versus 2004

The primary drivers of the $3,683,000 (9.1%) increase in operating expenses are organizational changes in 2005. Costs of $1,234,000 were recognized related to the replacements of the Company s Chief Executive and Chief Financial Officers. The expenses were primarily made up of severance compensation for the retiring executives, hiring expenses, and signing bonuses for the new executives. In the fourth quarter of 2005, the Company eliminated 22 employee positions resulting in $1,121,000 in severance expenses.

Operating expenses in 2005 included the write-off of $596,000 in capital projects determined to no longer be viable. The projects were primarily related to development of computer software applications.

Purchased services expenses in 2005 were higher by $532,000 compared to 2004. The primary driver of this increase is the costs related to the Company s Sarbanes-Oxley compliance work, with increased costs of $337,000 over 2004. Bad debts expense increased $325,000 over 2004. Driving this increase are higher gas costs resulting in higher customer bills. Management believes the increase also stems in part from the transition of customer service and collections activities from 15 offices to a single consolidated customer service call center. Employee benefits expense decreased $625,000. The primary drivers of the decrease were reductions in medical and dental expenses, for active employees, and in retiree medical expense.

Depreciation and amortization expense increased $949,000 reflecting higher depreciable assets resulting from capital spending.

NONOPERATING EXPENSE (INCOME)

An $801,000 reduction in net Nonoperating expense (income) in 2006 is primarily the result of interest income recognized with the receipt of two income tax refunds.

INCOME TAXES

The changes in the provision for income taxes from 2005 to 2006 and from 2004 to 2005 are attributable to the changes in pre-tax earnings, as well as an increase in the effective tax rate. The Company has incurred costs in connection with its pending merger. Certain of those costs are not deductible on the Company s tax return, and are permanent differences between book and tax income. The resulting increase in income taxes from the non-deductibility of these expenses was $596,000.

The changes in the provision for income taxes from 2004 to 2005 are primarily attributable to the changes in pre-tax earnings.

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 $60,000,000 bank revolving credit commitment. This agreement has a variable commitment fee and a term that expires in October 2007. The Company also has a $10,000,000 uncommitted line of credit. As of September 30, 2006, there were no outstanding borrowings under these credit lines.

Due to the nature of Cascade s business, which is characterized by reliable payments from a stable customer base and our expectations that capital spending will be primarily funded from internal sources, we expect to have limited need to source additional capital during fiscal year 2007. For this reason, combined with 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.

The table below shows the Company s future commitments under contractual obligations as of September 30, 2006:

Contract Category	Amounts Due by Fiscal Year 2007 (dollars in thousands)	2008	2009	2010	2011	Beyond 2011	Total
Long-term Debt	$ 8,000	$	$	$	$	$ 165,123	$ 173,123
Interest on Debt	11,652	11,567	11,567	11,567	11,567	149,830	207,750
Operating Leases	307	49	34	15	7	7	419
Gas Supply	269,757	226,038	144,696	77,738	40,219	3,240	761,688
Interstate Pipeline Transportation	33,415	50,689	50,503	47,438	45,435	234,193	461,673
Gas Storage and Peaking Services	2,605	2,720	3,094	3,094	3,094	53,584	68,191
Other Purchase Obligations	458	279	92	36	37	37	939
Total	$ 326,194	$ 291,342	$ 209,986	$ 139,888	$ 100,359	$ 606,014	$ 1,673,783

OPERATING ACTIVITIES

Cash provided by operating activities in 2006 improved $16.7 million over last year. In addition to improved net income, the primary factor was the net reduction in deferred gas cost funded by the Company, contributing $21.9 million. This improvement was partially offset by $6.5 million from the reversal of temporary differences between book and tax income related to deferred gas costs.

INVESTING ACTIVITIES

Cash used by investing activities was down $11.8 million compared to 2005. Part of the difference was due to $2.2 million of one-time specific system reinforcement expenditures and $1.0 million relating to the completed AMR and call center centralization projects in the first three quarters of fiscal year 2005. The remainder reflects the Company s new investment evaluation process implemented in the first quarter to assure that all capital spending provides an adequate return or is required for safety or regulatory compliance.

FINANCING ACTIVITIES

Other than the payment of dividends, the Company s primary financing activity in fiscal 2006 was the $12.5 million net reduction in short-term debt. This reduction in debt was facilitated by favorable operating cash flow and reduced capital spending.

ENVIRONMENTAL MATTERS

There are two claims against the Company for cleanup of alleged environmental contamination related to manufactured gas plant sites previously operated by companies that were subsequently merged into the Company.

The first claim was received in 1995 and relates to a site in Oregon. An investigation has shown that soil and groundwater contamination exists at the site. There are parties in addition to the Company that are potentially liable for cleanup of the contamination. Some of these other parties have shared in the costs expended to date to investigate the site, and it is expected that these and potentially other parties will share in the cleanup costs. Several alternatives for remediation of the site have been identified, with preliminary estimates for cleanup ranging from approximately $500,000 to $11,000,000. It is not known at this time what share, if any, of the cleanup costs will actually be borne by the Company. The Oregon Department of Environmental Quality (DEQ) is currently reviewing a Focused Feasibility Study prepared for the site and is expected to select a preferred alternative from that report. It is not known when the decision will be made by DEQ.

The second claim was received in 1997 and relates to a site in Washington. A preliminary investigation has determined that there is evidence of contamination at the site, but there is also evidence that other property owners may have contributed to the contamination. There is currently not enough information available to estimate the potential liability associated with this claim, but the Company and other parties may become involved in future investigation or remediation of the site as increased interest has been expressed concerning its potential for redevelopment. In particular, the Company is aware that the local city government has secured federal grants for further investigation of the site. At this time, no formal investigation plan has been communicated to the Company.

Management believes it has adequate insurance to cover the costs of the above two claims. In the event the insurance proceeds do not completely cover the costs, management intends to seek recovery from its customers through increased rates. There is precedent for such recovery through increased rates, as both the Washington Utilities and Transportation Commission (WUTC) and the Oregon Public Utilities Commission (OPUC) have previously allowed regulated utilities to increase customer rates to cover similar costs.

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.

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 accounting treatment intended to reflect the financial impact of regulation. For example, in establishing the rates to be charged to the Company s retail customers, the WUTC and the 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 expected to be established to recover costs that were incurred in a prior period. In this situation, following 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.

PENSION PLANS

The Company has a defined benefit pension plan substantially covering all union employees and salaried employees hired before September 30, 2003. The Company also provides executive officers with supplemental retirement, death and disability benefits. These plans are described in the footnotes to the financial statements in Part II, Item 8 of this report.

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 $3,940,000 in 2006 and $3,365,000 in 2005 to the pension and supplemental executive retirement plans, and expects to contribute approximately $3,500,000 in 2007.

The discount rate the Company selects for measuring its benefit obligation at September 30, 2006, is based on the Citigroup Pension Discount Curve, updated for yields through September 30, 2006.

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 2006 and 2005, the Company s assumed rate of return on plan assets was 7.75% and 8.25%, respectively. A reduction in the assumed rate of return would result in increases in pension liability and pension costs.

DERIVATIVES

The Company accounts for derivative transactions according to the provisions of FAS No. 133, Accounting for Derivative Instruments and Hedging Activities , as amended. This standard requires that the fair value of all derivative financial instruments be recognized as either assets or liabilities on the Company s balance sheet. The Company applies FAS No. 71 to periodic changes in fair market value of derivatives associated with supplies for core customers and records an offset in regulatory asset and regulatory liability accounts.

Most of the Company s contracts for purchase and sale of natural gas qualify for the normal purchase and normal sales exception under FAS No. 133, and are not required to be recorded as derivative assets and liabilities. Accordingly, for these contracts 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 of derivatives associated with supplies for non-core customers are recognized in earnings or, if hedge accounting is applied, in Other Comprehensive Income.

New Accounting Standards

Information on new accounting standards is included in the Notes to the Consolidated Financial Statements contained in Part II, Item 8, of this report.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company 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 currently 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 may redeem these obligations prior to normal maturities if warranted by market conditions.

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 Purchased Gas Cost Adjustment (PGA) mechanisms assure the recovery in customer rates of prudently incurred wholesale cost of natural gas purchased for the core market. The Company primarily utilizes financial derivatives, and to a lesser extent, fixed price physical supply contracts to manage risk associated with wholesale costs of natural gas purchased for customers. The fair value of these derivatives as of September 30, 2006 is a net liability of $41 million. We monitor the liquidity of our financial derivative contracts. Based on the existing open interest in the contracts held, we believe existing contracts to be liquid. All of our financial derivative contracts settle within the next four years, with the following estimated future cash payments: $25.3 million in 2007, $8.6 million in 2008, $6.8 million in 2009 and $0.3 million in 2010. These amounts will change based on market prices at the time contract settlements are fixed.

With respect to derivative arrangements covering natural gas supplies for core customers, periodic changes in fair market value are recorded in regulatory asset or regulatory liability accounts, pursuant to authority granted by the WUTC and OPUC, recognizing that settlements of these arrangements will be recovered through the PGA mechanism.

For derivative arrangements related to supplies for non-core customers, which are not covered by a PGA mechanism, periodic changes in fair market value are recognized in earnings or in Other Comprehensive Income.

FORWARD-LOOKING STATEMENTS

The Company s discussion in this report, or in any information incorporated herein by reference, may contain forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements, other than statements of historical facts, are forward-looking statements, including statements concerning plans, objectives, goals, strategies, and future events or performance. When used in Company documents or oral presentations, the words anticipate , believe , estimate , expect , objective , projection , forecast , goal , int or similar words are intended to identify forward-looking statements.

These forward-looking statements reflect the Company s current expectations, beliefs and projections about future events that we believe may affect the Company s business, financial condition and results of operations, and are expressed in good faith and are believed to have a reasonable basis. However, each such forward-looking statement involves risks, uncertainties and assumptions, and is qualified in its entirety by reference to the following important factors, among others, that could cause the Company s actual results to differ materially from those projected in such forward-looking statements:

- factors affecting regulatory approvals of the Company s proposed merger with MDU Resources Group, Inc.

- prevailing state and federal governmental policies and regulatory actions, including those of the Washington Utilities and Transportation Commission, the Oregon Public Utility Commission, and the U.S. Department of Transportation s Office of Pipeline Safety, with respect to allowed rates of return, industry and rate structure, purchased gas cost and investment recovery, acquisitions and dispositions of assets and facilities, operation and construction of plant facilities, the maintenance of pipeline integrity, and present or prospective wholesale and retail competition;

- weather conditions and other natural phenomena;

- unanticipated population growth or decline, and changes in market demand caused by changes in demographic or customer consumption patterns;

- changes in and compliance with environmental and safety laws, regulations and policies, including environmental cleanup requirements;

- competition from alternative forms of energy and other sellers of energy;

- increasing competition brought on by deregulation initiatives at the federal and state regulatory levels, as well as consolidation in the energy industry;

- 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;

- risks, including creditworthiness, relating to performance issues with customers and suppliers;

- risks resulting from uninsured damage to the Company s property, intentional or otherwise, or from acts of terrorism;

- unanticipated changes that may affect the Company s liquidity or access to capital markets;

- unanticipated changes in interest rates or in rates of inflation;

- economic factors that could cause a severe downturn in certain key industries, thus affecting demand for natural gas;

- unanticipated changes in operating expenses and capital expenditures;

- unanticipated changes in capital market conditions, including their impact on future expenses and liabilities relating to employee benefit plans;

- potential inability to obtain permits, rights of way, easements, leases, or other interests or necessary authority to construct pipelines, or complete other system expansions;

- changes in the availability and price of natural gas; and

- legal and administrative proceedings and settlements.

In light of these risks, uncertainties and assumptions, the forward-looking events and circumstances discussed in this report, or in any information incorporated herein by reference, may not occur and actual results could differ materially from those anticipated or implied in the forward-looking statements.

Any forward-looking statement by the Company is made only as of the date on which such statement is made. The Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which the statement is made or to reflect the occurrence of any unanticipated events. New factors emerge from time to time, and the Company is not able to predict all such factors, nor can it assess the impact of each such factor or the extent to which such factors may cause results to differ materially from those contained in any forward-looking statement. You are also advised to consult the other reports we file with the Securities and Exchange Commission as well as the disclosure under Risk Factors in Part I, Item 1A.

Item 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Cascade Natural Gas Corporation
Seattle, Washington

We have audited the accompanying consolidated balance sheets of Cascade Natural Gas Corporation and subsidiaries (the Company) as of September 30, 2006 and 2005, 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, 2006. Our audits also included the financial statement schedule listed in the Index under Item 15. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Cascade Natural Gas Corporation and subsidiaries as of September 30, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2006, 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.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company s internal control over financial reporting as of September 30, 2006, based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated December 6, 2006, expressed an unqualified opinion on management s assessment of the effectiveness of the Company s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP
Seattle, Washington
December 6, 2006

CASCADE NATURAL GAS CORPORATION
CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

	Year Ended September 30, 2006	2005	2004
	(Dollars in thousands except per-share data)		
Operating Revenues	$ 455,964	$ 326,500	$ 318,078
Less			
Gas purchases and other costs of sales	327,570	212,958	202,759
Revenue taxes	30,335	21,827	21,511
Operating Margin	98,059	91,715	93,808
Cost of Operations			
Operating expenses	44,454	44,223	40,540
Depreciation and amortization	17,861	17,274	16,325
Property and miscellaneous taxes	3,748	3,786	3,696
	66,063	65,283	60,561
Income from operations	31,996	26,432	33,247
Nonoperating Expense (Income)			
Interest	11,951	11,744	12,375
Interest charged to construction	(50)	(187)	(445)
	11,901	11,557	11,930
Amortization of debt issuance expense	396	372	618
Other	(1,545)	(376)	(162)
	10,752	11,553	12,386
Income Before Income Taxes	21,244	14,879	20,861
Income Taxes	8,755	5,632	7,559
Net Income	12,489	9,247	13,302
Other Comprehensive Income (Loss):			
Minimum pension liability adjustment	3,624	177	1,270
Unrealized losses on derivative commodity instruments	(3,558)		
Income tax	(32)	(56)	(448)
Other Comprehensive Income	34	121	822
Comprehensive Income	$ 12,523	$ 9,368	$ 14,124
Earnings Per Common Share, Basic and Diluted	$ 1.09	$ 0.82	$ 1.19
Dividends Paid Per Common Share	$ 0.96	$ 0.96	$ 0.96

The accompanying notes are an integral part of these consolidated financial statements.

CASCADE NATURAL GAS CORPORATION
CONSOLIDATED BALANCE SHEETS

	September 30, 2006	2005
	(Dollars in thousands)	
ASSETS		
Utility Plant	$ 614,184	$ 597,469
Less accumulated depreciation	273,138	257,008
	341,046	340,461
Construction work in progress	380	2,021
	341,426	342,482
Other Assets		
Investments in non utility property	202	202
Notes receivable, less current maturities	488	46
	690	248
Current Assets		
Cash and cash equivalents	8,593	1,128
Accounts receivable and current maturities of notes receivable, less allowance of $2,143 and $1,319 for doubtful accounts	22,796	23,163
Prepaid expenses and other assets	4,671	9,463
Derivative instrument asset energy commodity	4,135	91,957
Materials, supplies, and inventories	17,495	14,142
Deferred income taxes	1,779	2,292
Regulatory assets	26,504	
	85,973	142,145
Deferred Charges and Other		
Gas cost changes		16,630
Derivative instrument asset energy commodity	3,269	43,440
Regulatory assets	18,261	1,185
Other	7,087	6,775
	28,617	68,030
	$ 456,706	$ 552,905

The accompanying notes are an integral part of these consolidated financial statements.

CASCADE NATURAL GAS CORPORATION
CONSOLIDATED BALANCE SHEETS (Continued)

	September 30, 2006	2005
	(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, 11,505,996 and 11,413,019 shares	$ 11,506	$ 11,413
Additional paid-in capital	105,702	103,781
Accumulated other comprehensive loss	(12,453)	(12,487)
Retained earnings	17,372	15,908
	122,127	118,615
Long-Term Debt	165,123	173,840
Current Liabilities		
Short-term debt		12,500
Current maturities of long-term debt	8,000	
Accounts payable	14,647	17,841
Property, payroll, and excise taxes	5,776	5,520
Dividends and interest payable	6,939	6,920
Derivative instrument liability energy commodity	29,496	132
Regulatory liabilities	4,132	91,217
Other current liabilities	12,888	8,077
	81,878	142,207
Deferred Credits and Other Non-current Liabilities		
Income taxes	38,326	42,273
Investment tax credits	1,055	1,156
Retirement plan obligations	11,067	19,042
Derivative instrument liability energy commodity	18,939	1,326
Regulatory liabilities	12,035	50,584
Deferred gas cost credit	602	
Other	5,554	3,862
	87,578	118,243
Commitments and Contingencies (Note 12)		
	$ 456,706	$ 552,905

The accompanying notes are an integral part of these consolidated financial statements.

CASCADE NATURAL GAS CORPORATION
CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS EQUITY

	Common Stock Shares	Par Value	Additional Paid-In Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings
	(Dollars in thousands except per-share data)				
Balance, September 30, 2003	11,131,860	$ 11,132	$ 98,877	$ (13,430)	$ 15,051
Cash dividends:					
Common stock, $.96 per share					(10,783)
Other comprehensive income				822	
Issuance of common stock	136,209	136	2,477		
Net Income					13,302
Balance, September 30, 2004	11,268,069	11,268	101,354	(12,608)	17,570
Cash dividends:					
Common stock, $.96 per share					(10,909)
Other comprehensive income				121	
Issuance of common stock	144,950	145	2,427		
Net Income					9,247
Balance, September 30, 2005	11,413,019	11,413	103,781	(12,487)	15,908
Cash dividends:					
Common stock, $.96 per share					(11,025)
Other comprehensive income				34	
Issuance of common stock	92,977	93	1,921		
Net Income					12,489
Balance, September 30, 2006	11,505,996	$ 11,506	$ 105,702	$ (12,453)	$ 17,372

The accompanying notes are an integral part of these consolidated financial statements.

CASCADE NATURAL GAS CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30, 2006	2005	2004
	(Dollars in thousands)		
Operating Activities			
Net Income	$ 12,489	$ 9,247	$ 13,302
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	17,861	17,274	16,325
Deferrals of gas cost changes	6,464	(9,440)	(7,001)
Amortization of gas cost changes	10,768	5,098	6,296
Other deferrals and amortizations	(3,409)	76	1,099
Deferred income taxes and tax credits net	(3,535)	2,771	12,972
Change in current assets and liabilities	5,084	4,125	(10,427)
Net cash provided by operating activities	45,722	29,151	32,566
Investing Activities			
Construction expenditures	(20,464)	(28,893)	(39,465)
Customer contributions in aid of construction	4,446	882	446
Net cash used by investing activities	(16,018)	(28,011)	(39,019)
Financing Activities			
Proceeds from long-term debt, net		42,886	
Repayment of long-term debt	(717)	(14,060)	(22,030)
Changes in short-term debt	(12,500)	(21,000)	29,700
Proceeds from issuance of common stock	2,014	2,572	2,613
Dividends paid	(11,025)	(10,909)	(10,783)
Other	(11)		
Net cash used by financing activities	(22,239)	(511)	(500)
Net Increase (Decrease) in Cash and Cash Equivalents	7,465	629	(6,953)
Cash and Cash Equivalents			
Beginning of year	1,128	499	7,452
End of year	$ 8,593	$ 1,128	$ 499

The accompanying notes are an integral part of these consolidated financial statements.

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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, 2006, the Company had approximately 204,000 residential customers, 31,000 commercial customers, and 700 industrial and other larger customers. Approximately 200 of the larger industrial customers are non-core customers.

Residential, commercial, and smaller industrial customers are core 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 26% of gas deliveries and 73% 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. However, consumption is also influenced by energy efficiency of customers appliances as well as consumer decisions to reduce natural gas usage in response to higher prices.

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 inter-company transactions are eliminated in consolidation.

Reclassifications: Certain reclassifications have been made in the 2005 Consolidated Balance Sheet to conform to the classifications used in 2006 as follows:

- In Deferred Charges and Other, Regulatory assets of $1,185,000 had previously been included in Other at September 30, 2005.

- In Current Liabilities, Derivative instrument liability-energy commodity of $132,000 had previously been included in Other current liabilities at September 30, 2005.

- In Deferred Credits and Other Non-current Liabilities, Derivative instrument liability-energy commodity of $1,326,000 had previously been included in Other at September 30, 2005.

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, supervisory costs, general and administrative costs, and the 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 earnings.

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 2.9%. 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 determined based on discounted future cash flow.

The Company periodically reviews items, such as its franchises and easements, environmental, and other legal requirements, which may give rise to asset retirement obligations (ARO), and records such ARO s pursuant to the requirements of Statement of Financial Accounting Standards (FAS) 143, Accounting for Asset Retirement Obligations and FASB Interpretation (FIN) No. 47, Accounting for Conditional Asset Retirement Obligations an Interpretation of FASB Statement No. 143 .

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

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:

	2006	**2005**	**2004**
	(dollars in thousands)		
Changes in current assets and current liabilities:			
Accounts and notes receivable	$ (75)	$ (872)	$ (2,696)
Income taxes	6,043	2,062	(12,026)
Inventories	(3,352)	(875)	1,468
Prepaid expenses and other assets	(185)	(144)	(504)
Accounts payable and accrued expenses	1,319	3,925	3,967
Other	1,334	29	(636)
Net change in current assets and current liabilities	$ 5,084	$ 4,125	$ (10,427)
Cash payments:			
Interest (net of amounts capitalized)	$ 11,896	$ 11,637	$ 12,839
Income taxes	$ 10,052	$	$ 4,610

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

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Regulatory accounts: The Company follows Statement of 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, 2006 and 2005 include the following:

	2006	**2005**
	(dollars in thousands)	
Current Assets		
Gas supply hedging	$ 26,504	$
Non-current Assets		
Gas cost changes		16,630
Unamortized loss on reacquired debt	1,431	1,659
Gas supply hedging	18,261	1,185
Other	1,944	544
Current Liabilities		
Gas supply hedging	(4,132)	(91,217)
Non-current Liabilities		
Deferred income taxes	(7,999)	(7,044)
Gas supply hedging	(3,222)	(43,440)
Gas cost changes	(602)	
Other, net	(814)	(100)
Net	$ 31,371	$ (121,783)

Under Non-current Assets, regulatory assets related to Unamortized loss on reacquired debt, Gas supply hedging, and Other are included on the Consolidated Balance Sheets in Other Deferred Charges.

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.

Allowance for doubtful accounts: With respect to its residential and commercial customer accounts, the Company establishes an allowance for doubtful accounts based on its assessment of aged accounts receivable and on historical trends and ratios of write-offs to revenues. With respect to industrial customer accounts, which are generally significantly larger than residential and commercial, a specific allowance is established for accounts determined to be at risk of collection.

Leases: The Company leases a portion 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 $628,000, $641,000, and $776,000, for fiscal years ended September 30, 2006, 2005, and 2004, respectively.

Federal income taxes: 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 currently enacted tax rates. 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. With respect to utility plant placed in service after 1980, the Company calculates its deferred income tax provision to conform to the Federal normalization requirements, as approved by the WUTC and OPUC.

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 regulatory assets and regulatory liabilities 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, values of derivative instruments, unbilled revenue, in the determination of depreciable lives of utility plant, and in the measurement of asset retirement obligations.

Stock-based compensation: The Company applies FAS No. 123 (revised 2004), *Share-Based Payment* . Under this standard, the Company records the cost of employee services received in exchange for an award of its stock based on the fair value of the award as of the grant date. The cost is recognized over the period during which the employee is required to provide service in exchange for the award. Prior to fiscal 2006, the Company accounted 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.* See Note 7 for more information about the Company s stock-based compensation plan. Had compensation expense been determined in accordance with FAS No. 123, the Company s net income and earnings per share for 2005 and 2004 would have been as follows:

	2005		2004	
	(in thousands except per-share data)			
Net Income				
As reported	$	9,247	$	13,302
Less total stock-based employee compensation expense determined under the fair value method, net of tax	26		53	
Pro forma net income	$	9,221	$	13,249
Earnings per share, basic and diluted				
As reported	$	0.82	$	1.19
Pro forma	$	0.81	$	1.18

See also the discussion of **FAS No. 123 (revised 2004)** under **New Accounting Standards** below.

Comprehensive income (loss): Comprehensive income for the fiscal years ended September 30, 2006, 2005 and 2004, included Other Comprehensive Income of $34,000, $121,000, and $822,000, net of income tax. The charges are related to minimum pension liability adjustments and unrealized losses on energy commodity derivatives. See Note 11 for more information on the Company s minimum pension liability adjustments.

Segment reporting: Management views the Company as operating as a single segment, that of a local distribution company in the Pacific Northwest.

Derivatives: The Company records derivative transactions according to the provisions of FAS No. 133, *Accounting for Derivative Instruments and Hedging Activities* , as amended. This standard requires that the fair value of all derivative financial instruments be recognized as either assets or liabilities on the Company s balance sheet. With respect to derivative arrangements covering gas supplies for core customers, periodic changes in fair market value are recorded in regulatory asset or regulatory liability

accounts, pursuant to authority granted by the WUTC and OPUC, recognizing that settlements of these arrangements will be recovered through the Purchased Gas Cost Adjustment (PGA) mechanism.

The Company s contracts for purchase and sale of natural gas generally 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.

For derivative arrangements related to supplies for non-core customers, which are not covered by a PGA mechanism, the Company elects whether to apply hedge accounting to the derivative. If hedge accounting is applied, periodic changes in the fair market value are recorded in Other Comprehensive Income (OCI). Under hedge accounting, amounts recorded in OCI are reclassified into earnings in the period the hedged transaction affects earnings. If hedge accounting is not applied, periodic changes in fair market value are recognized in earnings.

NEW ACCOUNTING STANDARDS

FAS No. 151: In November 2004, the Financial Accounting Standards Board (FASB) issued FAS No. 151, *Inventory Costs* . This standard is an amendment of Accounting Research Bulletin (ARB) No. 43, clarifying the requirement that abnormal amounts of idle facility expense, freight, handling costs, and spoilage be recognized as current period costs. The Company s adoption of this standard on October 1, 2005 did not have a significant impact on the Company s financial statements.

FAS No. 123 R: In December 2004, FASB issued FAS No. 123 (revised 2004), ***Share-Based Payment*** **. This statement is a revision of FAS No. 123,** ***Accounting for Stock-Based Compensation*** **, and supersedes Accounting Principles Board (APB) Opinion No. 25,** ***Accounting for Stock Issued to Employees*** **. The Company adopted this standard effective October 1, 2005. Under FAS No. 123R, the Company is required to recognize as expense the fair value of equity instruments, including stock options, to be issued in exchange for goods or services. Adoption of this standard did not have a significant impact on the Company s financial statements. Disclosures required under this standard are included in Note 7 to the financial statements.**

FIN 47: In March 2005, the FASB issued FIN No. 47, *Accounting for Conditional Asset Retirement Obligation, an Interpretation of FASB Statement No. 143* . FIN 47 clarifies that the term conditional asset retirement obligation refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. Under FIN 47, the Company is required to recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when the Company would have sufficient information to reasonably estimate the fair value of an asset retirement obligation. The Company adopted FIN 47 as of September 30, 2006. Disclosures under this standard are included in Note 5 to the financial statements.

FAS No. 154: In May 2005, FASB issued FAS No. 154, *Accounting for Changes and Error Corrections* . This standard replaces APB Opinion No. 20 and FAS No. 3. The Company will be required to adopt this standard October 1, 2006. FAS No 154 changes the requirements for the accounting for and reporting of a change in accounting principle. FAS No. 154, requires retrospective application to prior periods financial statements of changes in accounting principle.

FAS No. 155: In February 2006, FASB issued FAS No 155, *Accounting for Certain Hybrid Financial Instruments, an amendment of FASB Statements No. 133 and 140.* This standard is effective for all financial instruments acquired after the beginning of an entity s first fiscal year beginning after September 15, 2006. The Company does not expect this standard to have a significant impact on its financial statements.

FAS No. 157: In September 2006, FASB issued FAS No. 157, *Fair Value Measurements*. This standard defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This standard is effective for financial statements issued for fiscal years beginning after November 15, 2007. The Company has not determined the impact this standard will have on its financial statements.

FAS No. 158: In September 2006, FASB issued FAS No. 158, *Employers Accounting for Defined Benefit Pension and Other Postretirement Plans an amendment of FASB Statements No. 87, 88, 106, and 132(R)* This standard requires a sponsor of defined benefit retirement plans to: (a) Recognize the funded status of a benefit plan in its balance sheet; (b) Recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs of credits that arise during the period but are not recognized as components of net periodic benefit cost; (c) Measure the defined benefit plan assets and obligations as of the date of the employer s fiscal year end; and (d) Disclose in the notes to financial statements additional information about certain effects on net periodic benefit cost for the next fiscal year that arise from the delayed recognition of the gains or losses, prior service costs or credits, and transition asset or obligation. The Company will be required to initially recognize the funded status of its defined benefit plans and to provide the required disclosures as of the end of its fiscal year ending September 30, 2007. The Company has not yet determined the impact of this standard on its financial statements.

FIN 48: In June 2006, FASB issued FIN 48, *Accounting for Uncertainty in Income Taxes an interpretation of FASB Statement No. 109*. This Interpretation clarifies the accounting for uncertainty in income taxes recognized in an enterprise s financial statements in accordance with FASB Statement No. 109, *Accounting for Income Taxes.* This Interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This Interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure, and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. The Company has not determined the impact of this interpretation on its financial statements.

SAB 108: In August 2006, the Staff of the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) 108. SAB 108 provides that registrants should use both a balance sheet approach and an income statement approach when quantifying and evaluating the materiality of a misstatement. SAB 108 is effective for annual financial statements covering the first fiscal year ending after November 15, 2006. Early adoption of SAB 108 in 2006 did not have a significant impact on the Company s financial statements.

Note 3 Earnings Per Share

The following table sets forth the calculation of earnings per share:

	2006	2005	2004
	(in thousands except per-share data)		
Net Income	$ 12,489	$ 9,247	$ 13,302
Weighted average shares outstanding	11,468	11,339	11,209
Plus: Issued on assumed exercise of stock options	1	3	13
Weighted average shares outstanding assuming dilution	11,469	11,342	11,222
Earnings per common share, basic	$ 1.09	$ 0.82	$ 1.19
Earnings per common share, diluted	$ 1.09	$ 0.82	$ 1.19

The only dilutive securities are the stock options described in Note 7.

Note 4 Utility Plant

Utility plant at September 30, 2006 and 2005 consists of the following components:

	2006	2005
	(dollars in thousands)	
Distribution plant	$ 548,453	$ 531,497
Transmission plant	14,675	14,693
General plant	46,942	47,165
Intangible plant	212	212
Nondepreciable plant	3,902	3,902
	$ 614,184	$ 597,469

Note 5 Asset Retirement Obligations

The Company follows FAS No. 143, Accounting for Asset Retirement Obligations which requires the recording of the fair market value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the associated costs of the asset retirement obligation are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. Upon retirement of the asset, the Company either settles the retirement obligation for its recorded amount or incurs a gain or loss. As asset retirement costs are recovered through rates charged to customers, the Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and asset retirement obligations recorded under SFAS 143. The regulatory assets do not earn a return. The adoption of SFAS No. 143 on October 1, 2002 did not have a material effect on the Company s financial condition, results of operations or cash flows.

As described in Note 2, the Company adopted FIN 47 as of September 30, 2006, which has resulted in the recording of additional asset retirement obligations under FAS No. 143. Specifically, the Company has recorded liabilities for future asset retirement obligations to remove certain pipe and storage tanks. With the adoption of FIN 47, the Company recorded an asset retirement obligation of $389,000**,** a regulatory asset of $352,000**,** capitalized asset retirement costs of $45,000, and related accumulated depreciation of $8,000. Due to an inability to estimate a range of settlement dates, the Company cannot estimate a liability for removal and disposal of certain transmission and distribution assets, as well as abatement of asbestos for certain buildings.

The following table documents the changes in the Company s asset retirement obligation during the year ended September 30, 2006 (dollars in thousands):

Asset retirement obligation at beginning of year	$
Asset retirement obligation recognized during the year	389
Asset retirement obligation at end of year	$ 389

The pro forma asset retirement obligation liability balances as if FIN 47 had been adopted on October 1, 2004 (rather than September 30, 2006) are as follows (dollars in thousands):

Pro forma asset retirement obligation as of October 1, 2004	$ 344
Pro forma asset retirement obligation as of September 30, 2005	$ 366

Note 6 Common Stock

At September 30, 2006, shares of common stock are reserved for issuance as follows:

	Number of shares
Employee Savings Plan and Retirement Trust (401(k) plan)	169,640
Dividend Reinvestment Plan	113,882
Director Stock Award Plan	22,112
Stock Incentive Plan (Note 7)	319,730
	625,364

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

Note 7 Share-Based Payment

As of September 30, 2006, the company has three share-based compensation plans which are described below. Compensation cost recorded for those plans was $400,000, $259,000 and $51,000 for 2006, 2005, and 2004, respectively. None of this cost was capitalized as part of inventory or fixed assets. Total income tax benefit recognized in the income statement for share-based compensation arrangements was $154,000, $98,000, and $18,000 for 2006, 2005, and 2004, respectively.

1998 Stock Incentive Plan

Under the Company s 1998 Stock Incentive Plan (the Plan), officers and other key management employees may be granted options to purchase stock or other equity-based incentives. The grants vest 1⁄3 per year over three years. Options granted in 2001 that were not exercised expired in 2006. Options granted in 2002 fully vested in 2005 and expire ten years from the grant date. The intrinsic value method was used to account for these options and no compensation expense was recognized. No options were granted in 2004, 2005, or 2006. A summary of option activity under the Plan as of September 30, 2006, and changes during the year is presented below:

Options	**2006 Wtd. Avg. Exercise Price**	**No. Shares Under Option**
Outstanding at October 1, 2005	$ 19.95	73,899
Granted	N/A	
Exercised	$ 19.23	(23,899)
Forfeited or expired	$ 19.75	(25,000)
Balance at September 30	$ 20.84	25,000
Exercisable at September 30	$ 20.84	25,000

The remaining average weighted life of options outstanding at September 30, 2006 is 5.5 years.

	2006 (in thousands)	**2005**	**2004**
Intrinsic value of options exercised	$ 54	$ 201	$ 222
Fair value of options vested	$	$ 26	$ 53

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Restricted Stock Grants

The Company s employment contracts entered in 2005 with its Chief Executive Officer (CEO) and its former Chief Financial Officer (CFO) contain grants of restricted stock. Under the CEO grant, 5,000 shares were restricted until the CEO completed one year of employment, and another 5,000 shares are restricted until he completes two years of employment. Under the CFO grant, 5,000 shares were restricted until he completed one year of employment. During this period, each executive is restricted from selling his shares. The value of the shares granted is based on the market value as of the grant date. During 2006 and 2005, the Company recognized $175,000 and $197,000 as compensation expense under this plan. As of September 30, 2006, $25,000 remains to be recognized as expense over the first two quarters of fiscal 2007.

2000 Director Stock Award Plan

Under the Company s 2000 Director Stock Award Plan, each non-employee director is awarded 1,000 shares of the Company s common stock annually following shareholder approval at the February 2006 annual meeting. Prior to 2006, the annual awards were 500 shares to each non-employee director. The Company recognized $225,000, $62,000, and $51,000 as expense under this plan in 2006, 2005, and 2004 respectively.

Note 8 Short-Term Debt

The Company s short-term borrowing needs are met with a three-year, $60,000,000 revolving credit agreement with one of its banks. This agreement has a variable commitment fee and a term that expires in October 2007. The Company also has a $10,000,000 uncommitted line of credit. The following table sets forth information on the two credit lines:

	2006 (dollars in thousands)	2005	2004
Amount outstanding at September 30	$	$ 12,500	$ 33,500
Average daily balance outstanding	$ 4,110	$ 19,204	$ 4,511
Average interest rate, excluding commitment fee	4.08 %	3.35 %	2.29 %
Maximum month-end amount outstanding	$ 18,900	$ 45,000	$ 33,500

Various debt and credit agreements restrict the Company and its subsidiaries as to indebtedness, payment of cash dividends on common stock, and other matters. As of September 30, 2006, the Company is in compliance with all restrictive covenants of its debt agreements.

Note 9 Long-Term Debt

Long-term debt and current maturities of long-term debt at September 30, 2006 and 2005 consist of the following:

	2006	2005
	(dollars in thousands)	
Medium-term Notes:		
8.50% due Oct. 2006	$	$ 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
5.21% Notes due September 2020	15,000	15,000
7.50% Notes due November 2031	39,831	39,840
5.25% Insured Quarterly Notes due February 2035	29,292	30,000
Total long-term debt	$ 165,123	$ 173,840
Current Maturities		
Medium-term Notes:		
8.50% due Oct. 2006	$ 8,000	$

None of the long-term debt includes sinking fund requirements.

The 5.21% Notes due September 2020 are redeemable at the option of the Company, in whole or in part, at a redemption price determined under make-whole provisions described in the prospectus supplement.

The 7.50% Notes due November 2031 are redeemable at the option of the Company, in whole or in part, on or after November 15, 2006. The 7.50% Notes due November 2031 are subject to redemption at the option of the representative of a deceased beneficial owner. The maximum annual required redemption per deceased beneficial owner is $25,000, principal amount, and $1,200,000 for all deceased beneficial owners of the Notes.

The 5.25% Insured Quarterly Notes due February 2035 are redeemable at the option of the Company, in whole or in part, on or after February 1, 2010. The 5.25% Insured Quarterly Notes due February 2035 are subject to redemption at the option of the representative of a deceased beneficial owner. The maximum required redemption per deceased beneficial owner is $25,000, principal amount, and $600,000 for all deceased beneficial owners of the Notes.

Annual obligations for redemption of long-term debt and current maturities are as follows: $8,000,000 in fiscal year 2007, none in fiscal years 2008, 2009, 2010 and 2011, and $165,123,000 thereafter.

There are $89 million, including $8 million current maturities, Medium-Term Notes (MTN s) outstanding as of September 30, 2006. The 5.21% Notes due September 2020, the 7.50% Notes due November 2031, and the 5.25% Insured Quarterly Notes due February 2035 were issued under a 2001 shelf registration providing ability to issue up to $150 million long-term debt and equity securities. As of September 30, 2006, that registration statement has $65 million available for issuance.

Note 10 Income Taxes

The provision for income tax expense consists of the following:

	2006	2005	2004
	(dollars in thousands)		
Current tax expense	$ 11,734	$ 1,844	$ (7,416)
Deferred tax expense	(2,878)	3,934	15,151
Amortization of deferred investment tax credits	(101)	(146)	(176)
Total income tax expense	$ 8,755	$ 5,632	$ 7,559

A deferred income tax charge associated with accruals of minimum pension liability is included in Other Comprehensive Income (OCI) for each year ended September 30 as follows: $1,327,000 in 2006, $56,000 in 2005, and $448,000 in 2004. Also included in 2006 was a deferred income tax benefit of $1,295,000, related to unrealized gains / losses on energy commodity derivatives.

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

	2006	2005	2004
	(dollars in thousands)		
Statutory federal income tax rate	35 %	35 %	35 %
Income tax calculated at statutory federal rate	$ 7,435	$ 5,208	$ 7,301
Increase (decrease) resulting from:			
State income tax, net of federal tax benefit	62	225	60
Non-normalized depreciation differences	697	327	364
Permanent difference for non-deductible merger-related expenses	596		
Amortization of investment tax credits	(101)	(146)	(176)
Other	66	18	10
	$ 8,755	$ 5,632	$ 7,559
Effective tax rate	41.2 %	37.9 %	36.2 %

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, 2006, the balance of the net regulatory liability is $7,632,000.

The tax effects of significant items comprising the Company s deferred income tax accounts at September 30, 2006 and 2005 are as follows:

	2006	2005
	(dollars in thousands)	
Current Amount:		
Deferred assets:		
Allowance for doubtful accounts	$ 836	$ 527
Accrued liabilities	543	542
Alternative minimum tax credit		1,136
Other	400	87
	$ 1,779	$ 2,292
Non-current Amounts:		
Deferred tax liabilities:		
Basis differences on net fixed assets	$ 42,861	$ 41,276
Deferred gas costs		6,503
Debt refinancing costs	512	595
Retirement benefit obligations	3,636	3,135
Other		168
	47,009	51,677
Deferred tax assets:		
Retirement benefit obligations	1,532	2,282
Other comprehensive income	6,948	6,979
Other	203	143
	8,683	9,404
Net non-current deferred tax liability	$ 38,326	$ 42,273

Note 11 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. Under a plan amendment effective October 1, 2003, non-bargaining-unit employees no longer accrue benefits under the plan. Benefits accrued as of that point were frozen for those employees. Employees covered by a bargaining agreement accrue benefits based on a formula that includes credited years of service and the employee s annual compensation. Effective January 1, 2007 for field operations bargaining unit employees hired before that date, pension benefits will accrue a benefit of $107 per month for each full year of service. They will no longer accrue benefits based on compensation.

The Company has also provided executive officers with supplemental retirement, death, and disability benefits. This plan was also frozen September 30, 2003 for further accruals and for new participants. 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 employment contract for the Chief Executive Officer provides for a supplemental defined-contribution retirement plan that is designed to provide for a retirement income target of 55% of final pay after taking into consideration benefits earned from other retirement plans and Social Security.

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, 2006, the Company s matching contribution percentage was increased from 50% to 75% with respect to non-bargaining-unit employees. Effective January 1, 2007, the matching contribution for field operations bargaining unit employees hired before that date will be reduced to 25% from 75%. Field operations bargaining unit employees hired after January 1, 2007 will receive a matching contribution of 50%. The Company recognized costs for matching contributions of $747,000, $621,000, and $728,000, for 2006, 2005, and 2004, respectively.

In addition to the existing match of non-bargaining-unit and customer service representative employee contributions, the Company contributes 4% of eligible salaries, and a 1% to 4% transition contribution, to employee retirement accounts. For field operations bargaining unit employees hired after January 1, 2007, the Company will contribute 4% of eligible pay. The Company recognized $926,000, $956,000 and $973,000 for 2006, 2005, and 2004, respectively, under this plan. Additionally, there are annually determined profit-sharing contributions based on the Company achieving established targets. Under this profit-sharing plan, the Company recognized $890,000 for 2006, and none for 2005 or 2004. 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 that began January 1, 2004. Beginning in 2006, with respect to plan participants over age 65, the Company provides these benefits through insurance coverage.

The following tables set forth the pension and health care plan disclosures. The amounts shown in the tables under Pension Benefits represent the aggregate amounts of the employee pension and the executive supplemental retirement defined benefit plans. Amounts shown under Other Benefits represent the retiree medical plan. The measurement date of plan assets and obligations is as of September 30 for each year presented:

Components of net periodic benefit cost

	Pension Benefits			**Other Benefits**		
	2006	**2005**	**2004**	**2006**	**2005**	**2004**
	(dollars in thousands)					
Service cost	$ 866	$ 788	$ 768	$ 113	$ 140	$ 160
Interest cost	3,860	3,843	3,728	658	1,101	1,270
Expected return on plan assets	(4,405)	(4,162)	(3,913)	(877)	(846)	(853)
Amortization of prior service cost	152	182	229	(2,463)	(1,320)	(1,319)
Recognized net actuarial loss / (gain)	1,685	1,544	1,397	723	747	961
Net periodic benefit cost	2,158	2,195	2,209	(1,846)	(178)	219

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	Pension Benefits 2006	2005	Other Benefits 2006	2005
	(dollars in thousands)			
Change in benefit obligations				
Projected benefit obligation at beginning of year	$ 71,729	$ 65,523	$ 12,418	$ 18,960
Service Cost	866	788	113	140
Interest Cost	3,860	3,843	658	1,101
Plan participants contributions			284	67
Amendments	(2,452)		(1,429)	(7,393)
Benefits paid	(3,163)	(2,880)	(1,359)	(870)
Changes in assumptions	(2,245)	4,388		
Actuarial (gain)/loss	160	67	1,199	413
Projected benefit obligation at end of year	68,755	71,729	11,884	12,418
Change in plan assets				
Fair value of plan assets at beginning of year	58,501	51,332	11,513	10,935
Actual return on plan assets	5,434	6,684	1,675	1,188
Employer contributions	3,940	3,365	161	193
Plan participants contributions			284	67
Benefits Paid	(3,163)	(2,880)	(1,359)	(870)
Fair value of plan assets at end of year	64,712	58,501	12,274	11,513
Funded Status	(4,043)	(13,228)	390	(905)
Unrecognized prior service cost	(1,959)	645	(13,980)	(15,013)
Unrecognized net (gain)/loss	18,935	23,734	9,189	9,511
Net amount recognized	$ 12,933	$ 11,151	$ (4,401)	$ (6,407)
Amounts recognized in the balance sheet consist of:				
Prepaid pension cost	$ 3,751	$ 3,669	$	$
Accrued pension (liability)	(6,661)	(12,630)	(4,401)	(6,407)
Intangible asset		645		
Accumulated other comprehensive (income) loss	15,843	19,467		
Net amount recognized	$ 12,933	$ 11,151	$ (4,401)	$ (6,407)
Accumulated Benefit Obligation	$ 68,756	$ 69,161		

For the fiscal year ending September 30, 2007, the Company expects to contribute approximately $3,500,000 to the employee pension plan and none to the supplemental executive retirement plan. The 2007 funding levels for the retiree medical plan have not been determined.

Expected Future Benefit Payments

Fiscal year ending September 30	Pension Benefits	Other Postretirement Benefits
	(dollars in thousands)	
2007	$ 3,037	$ 828
2008	$ 3,205	$ 850
2009	$ 3,409	$ 887
2010	$ 3,589	$ 913
2011	$ 3,733	$ 923
Next five years	$ 21,355	$ 4,643

	Discount Rate For Benefit Obligation 2006	2005	For Annual Benefit Cost 2006	2005	Average Compensation Increase 2006	2005	Expected Return on Plan Assets 2006	2005
Weighted Average Assumptions								
Pension plan	5.75 %	5.50 %	5.50 %	6.00 %	3.50 %	3.50 %	7.75 %	8.25 %
Supplemental executive retirement plan	5.75 %	5.50 %	5.50 %	6.00 %	N/A	N/A	7.75 %	8.25 %
Postretirement medical benefit plan	5.70 %	5.50 %	5.50 %	6.00 %	N/A	N/A	7.75 %	8.25 %

Assumed Health Care Cost Trend Rates

	2006	2005
Medical before Age 65		
Initial rate	8.0 %	8.5 %
Trends down to 5.5% ultimate rate by 2012		
Prescription Drugs Before Age 65		
Initial rate	12.0 %	13.0 %
Trends down to 5.5% ultimate rate by 2015		
Medical and Prescription Drugs for Age 65 and Over		
Initial rate	8.0 %	10.0 %
Trends down to 5.5% ultimate rate by 2012		

A one-percent change in the assumed health care cost trend rate would have the following effects as of September 30, 2006:

	One Percentage Point Increase (dollars in thousands)	Decrease
Effect on service and interest cost for year ended September 30, 2006	$ 57	$ (50)
Effect on accumulated postretirement benefit obligation as of September 30, 2006	$ 843	$ (747)

The following information regarding asset allocation, development of expected rate of return on plan assets, and investment strategy is presented separately for each of the three plans.

Employee Pension Plan

Investment Policy Summary

The fundamental investment objective of the Employee Pension Plan (the Plan) is to provide a rate of return sufficient to fund the retirement benefits under the Plan at a reasonable cost to the plan sponsor, Cascade Natural Gas Corporation, and commensurate with an appropriate amount of risk pursuant to the Plan obligations. At a minimum, the rate of return should equal or exceed the discount rate assumed by the Plan s actuaries in projecting the funding cost of the Plan under applicable ERISA standards. To do so, the Company s Pension Committee (the Committee) may appoint one or more investment managers to invest all or portions of the assets of the Plan (collectively referred to as the Fund) in accordance with specific investment guidelines, objectives, standards, and benchmarks.

Because the Committee expects the Fund s investment income, when combined with anticipated contributions by the Company, to exceed the sum of benefit payments and expenses over the next several years, the Committee intends that the Fund be managed to achieve long-term returns, with only a small percentage of the Fund invested in cash.

The Fund is divided into the following segments based on the guidelines below:

	Target	Minimum	Maximum
Cash & Cash Equivalents	0 %	0 %	20 %
Equity Securities	50 %	40 %	60 %
Fixed Income Securities	40 %	30 %	50 %
Real Estate	10 %	5 %	15 %

Asset Allocation

The asset allocation at September 30, 2006, and 2005, by major asset category is as follows:

	2006	2005
Cash & Cash Equivalents	2 %	6 %
Equity Securities	50 %	46 %
Fixed Income Securities	38 %	39 %
Real Estate	10 %	9 %

Discount Rate

The discount rate for measurement of the benefit obligation was developed using the Citigroup Pension Discount Curve, updated for yields through September 30, 2006.

The discount rate for the annual benefit cost was based on the Moody s Aa Corporate Bond Index measured as of September 30, 2005.

Expected Long-term Rate of Return on Plan Assets

The expected long-term rate of return on assets assumption is based on historical experience and consultation with the Company s actuarial consultants. Factors considered include asset allocation and expected returns attributable to each category of assets over a 20-year time horizon.

Additional Year-end Information (for plans with accumulated benefit obligation in excess of plan assets)

The amounts listed in the following table apply only to the employee retirement plan. This plan has an accumulated benefit obligation in excess of plan assets, resulting in the amounts shown in the table:

	Employee Pension Plan	
	2006	2005
	(dollars in thousands)	
Projected benefit obligation	$ 62,464	$ 65,418
Accumulated benefit obligation	$ 62,464	$ 62,850
Fair value of assets	$ 55,803	$ 50,220
Other comprehensive (income) loss	$ 15,843	$ 19,467
(Increase) / decrease in intangible asset	$ 644	$ 182
Increase (decrease) in additional minimum liability	$ (4,268)	$ (360)

Supplemental Executive Retirement Plan (SERP)

Investment Policy Summary

SERP assets are in insurance policies and managed investments. The value of insurance policies at September 30, 2006 was $5,995,000, and at September 30, 2005 was $5,435,000. The managed assets are divided into the following segments with the following weightings:

	Target	**Minimum**	**Maximum**
Equity Securities	65 %	50 %	80 %
Fixed Income Securities	25 %	15 %	40 %
Other	10 %	0 %	30 %

Asset Allocation

The allocation of assets at September 30, 2006, and 2005, by major asset category including life insurance policies, is as follows:

	2006	**2005**
Cash & Cash Equivalents	1 %	2 %
Equity Securities	24 %	23 %
Fixed Income Securities	8 %	8 %
Life Insurance Cash Value	67 %	65 %
Real Estate	0 %	2 %

Discount Rate

The discount rate for measurement of the benefit obligation was developed using the Citigroup Pension Discount Curve, updated for yields through September 30, 2006.

The discount rate for the annual benefit cost was based on the Moody s Aa Corporate Bond Index measured as of September 30, 2005.

Expected Long-term Rate of Return on Plan Assets

The expected long-term rate of return on assets assumption is based on historic experience with the investment manager and consultation with the Company s actuarial consultants. Factors considered include asset allocation and expected returns attributable to each category of assets over a 20-year time horizon.

Retiree Medical Plans

Investment Policy Summary

The fundamental investment objective of the Trusts (voluntary employee benefit associations within the meaning of Section 501(c)(9) of the Internal Revenue Code) is to provide a rate of return sufficient to fund medical benefits under the Company s medical plan at a reasonable cost to the plan sponsor, Cascade Natural Gas Corporation, and commensurate with an appropriate amount of risk pursuant to the Trusts obligations. The Company has appointed a qualified actuary to determine the benefit obligation under the medical plan (including post-retirement benefits) and the necessary funding to meet those obligations. In performing this analysis, the actuary has used appropriate actuarial methods for medical benefits and complies with existing financial accounting standards.

The Fund is divided into the following segments with the following weightings:

	Target	Minimum	Maximum
Cash	10 %	0 %	30 %
Equity Securities	65 %	25 %	90 %
Fixed Income Securities			