# SECURITIES AND EXCHANGE COMMISSION
**Washington, D. C. 20549**

# FORM 10-K

(Mark One)

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

**For the fiscal year ended December 31, 2006**

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________

Commission file number 1-15973

NW Natural

## NORTHWEST NATURAL GAS COMPANY
(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Oregon** | **93-0256722** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

**220 N.W. Second Avenue, Portland, Oregon 97209**
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: **(503) 226-4211**

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

| Title of each class | Name of each exchange on which registered |
|---|---|
| Common Stock | 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 [ X ] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. [ ]

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [ X ] No [ ]

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

Indicate by check mark whether the registrant is a large accelerated filer (as defined in Rule 12b-2 of the Act).
Yes [ X ] No [ ]

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

As of June 30, 2006, the registrant had 27,547,346 shares of its Common Stock 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 $1,010,618,119.

Indicate number of shares outstanding of each of registrant's classes of common stock as of February 23, 2007:

| | |
|---|---|
| Common Stock | 27,256,341 |

DOCUMENTS INCORPORATED BY REFERENCE

List documents incorporated by reference and the Part of the Form 10-K into which the document is incorporated.

Portions of the Proxy Statement of Company, to be filed in connection with the 2007 Annual Meeting of Shareholders, are incorporated by reference in Part III.

NORTHWEST NATURAL GAS COMPANY
Annual Report to Securities and Exchange Commission
on Form 10-K
For the Fiscal Year Ended December 31, 2006

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## GLOSSARY OF TERMS

**Basic earnings per share:** earnings applicable to common stock for a period, divided by the average number of shares of common stock outstanding during that period.

**Bcf:** one billion cubic feet, a volumetric measure of natural gas, roughly equal to 10 million therms.

**Btu:** British thermal unit, a basic unit of thermal energy measurement. One Btu equals the energy required to raise one pound of water one degree Fahrenheit. One hundred thousand Btu's equal one therm.

**Bypass:** a direct connection to the interstate gas pipeline, which circumvents the pipes of the local gas distribution company; usually considered only by large industrial users.

**Core utility customers:** residential, commercial and industrial firm service customers on our distribution system.

**Decoupling:** a rate mechanism which is designed to break the link between earnings and the quantity of natural gas consumed by customers. The design is intended to allow the utility to encourage customers to conserve energy while not adversely affecting its earnings due to losses in sales volumes.

**Degree days:** units of measure that reflect temperature-sensitive consumption of natural gas, calculated by subtracting the average of a day's high and low temperature from 65 degrees Fahrenheit.

**Demand charge:** a component in all core utility gas rates that covers the cost of securing pipeline capacity to meet peak demand, whether that capacity is used or not.

**Design day:** a design day is the maximum anticipated demand on the natural gas distribution system during a 24-hour period assuming weather at an average temperature of 12 degrees Fahrenheit, the coldest day in the last 20 years in our service territory.

**Diluted earnings per share:** earnings applicable to common stock for a period, divided by the average number of shares of stock that would be outstanding assuming the issuance of common shares for all existing stock based compensation plans with a dilutive impact during the reporting period.

**Firm service:** natural gas service offered to customers under contracts or rate schedules that will not be disrupted to meet the needs of other customers, particularly during cold weather.

**Gas storage:** a means of holding gas in reserve for future delivery, either through injection into an underground storage field, or storing it in the form of liquefied natural gas.

**General rate case:** a periodic filing with state regulators to establish equitable rates and balance the interests of all classes of customers and our shareholders.

**Interruptible service:** natural gas service offered to customers (usually large commercial or industrial) under contracts or rate schedules that allow for temporary interruptions to meet the needs of firm service customers.

**Liquefied natural gas (LNG):** the cryogenic liquid form of natural gas. At temperatures below minus 258 degrees Fahrenheit, natural gas can be stored in a liquid form, which is 600 times more dense than its gaseous form.

**Margin:** gross revenues less the associated cost of sales. Also referred to as net operating revenues.

**Purchased Gas Adjustment (PGA):** also known as the gas cost tracker, is a regulatory mechanism for annually adjusting customer rates due to changes in gas commodity costs.

**Return on equity (ROE):** a measure of corporate profitability, calculated as net income divided by average common stock equity. Authorized ROE refers to the equity rate approved by a regulatory agency for utility investments funded by common stock equity.

**Return on invested capital:** a measure of profitability calculated by dividing net income before interest expense by average long-term capital.

**Sales service:** service provided to a customer that receives both natural gas supply and transportation of that gas from the regulated utility.

**Therm:** the basic unit of natural gas measurement, equal to 100,000 Btu's. An average residential customer in our service area uses about 700 therms in an average-weather year.

**Transportation service:** service provided to a customer that secures its own natural gas supply and pays the regulated utility only for use of the distribution system to transport it.

**Underground gas storage:** storage of natural gas by injection into underground rock formations; historically gas is withdrawn during the winter heating season or during periods of high gas prices.

**Utility margin:** utility gross revenues less the associated cost of gas and applicable revenue taxes. Also referred to as utility net operating revenues.

**Weather normalization:** a rate mechanism that allows a utility to adjust customers' bills during the winter heating season to reduce variations in margin recovery due to fluctuations from average temperatures.

**Winter heating season:** generally considered to be the period from November through March.

NORTHWEST NATURAL GAS COMPANY
PART I

## ITEM 1. BUSINESS

### General

Northwest Natural Gas Company was incorporated under the laws of Oregon in 1910. Our company and its predecessors have supplied gas service to the public since 1859. Since September 1997, we have been doing business as NW Natural.

### Business Segments

#### Local Gas Distribution

We are principally engaged in the distribution of natural gas in Oregon and southwest Washington. In this report our principal business segment is referred to as local gas distribution or utility. Local gas distribution involves purchasing gas from producers, transporting the gas over interstate pipelines from the supply basins to our service territory, and reselling the gas to customers at rates and terms approved by the Oregon Public Utility Commission (OPUC) or by the Washington Utilities and Transportation Commission (WUTC). Gas distribution also includes transporting gas owned by large customers from the interstate pipeline connection, or city gate, to the customers' facilities for a fee, also approved by the OPUC or WUTC. Approximately 98 percent of our consolidated assets are related to the local gas distribution segment. The OPUC has allocated to us as our exclusive service area a major portion of western Oregon, including the Portland metropolitan area, most of the Willamette Valley and the coastal area from Astoria to Coos Bay. We also hold certificates from the WUTC granting us exclusive rights to serve portions of three southern Washington counties bordering the Columbia River. Gas service is provided in 122 cities and neighboring communities, in 15 Oregon counties, as well as in 14 cities and neighboring communities in three Washington counties. The city of Portland is the principal retail and manufacturing center in the Columbia River Basin, and is a major port for trade with Asia.

At year-end 2006, we had 575,116 residential customers, 60,523 commercial customers and 945 industrial sales customers. Approximately 90 percent of our customers are located in Oregon and 10 percent are in Washington. Industries served include: pulp, paper and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery and textiles; the manufacture of asphalt, concrete and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation. No individual customer or industry accounts for a significant portion of our industrial revenues.

#### Gas Storage

The gas storage business segment (previously referred to as Interstate Gas Storage) includes NW Natural's underground natural gas storage services to large intrastate and interstate customers using NW Natural's storage and related transportation capacity that is in excess of the utility's core (residential, commercial and industrial firm) customer requirements. Additionally, an independent energy marketing company provides asset optimization services to the utility under a contractual arrangement. Approximately 2 percent of our consolidated assets and 9 percent of consolidated net income in 2006 are related to the gas storage business segment. For each of the years ended December 31, 2006, 2005 and 2004, this business segment derived a majority of its revenues from five storage customers. The largest of these customers is served under a long-term contract. The total working gas capacity of the Mist underground gas storage facility has been revised from 13.9 Bcf to around 14 Bcf to reflect reservoir performance and incremental growth in certain reservoir pools. Of this capacity, the gas storage business included in this segment has access to about 5 Bcf of capacity while the core utility has access to the remaining 9 Bcf.

Pre-tax income from gas storage and third-party optimization is subject to revenue sharing with core utility customers. In Oregon, 80 percent of the pre-tax income is retained by this segment when the costs of the capacity used have not been included in utility rates, or 33 percent of the pre-tax income is retained when the capacity costs have been included in utility rates. The remaining 20 percent and 67 percent of pre-tax income, respectively, are deferred to a regulatory account for crediting to our core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from gas storage services and third-party optimization.

***Interstate Gas Storage.*** This part of the business segment provides firm and interruptible gas storage and related transportation services on NW Natural's system to several interstate customers. The interstate storage services and maximum rates are authorized by the Federal Energy Regulatory Commission (FERC). The storage capacity used by this business has been developed by NW Natural in advance of core utility customers' requirements.

***Intrastate Gas Storage.*** In February 2006, we began providing an Oregon firm intrastate gas storage service under an OPUC-approved rate schedule. The firm storage service terms and conditions mirror the firm interstate storage service, except that these customers are located and served in Oregon under an OPUC-approved rate schedule that includes service and site-specific qualifications.

***Third Party Optimization.*** NW Natural has a contract with an independent energy marketing company to optimize the value of our assets, primarily through the use of commodity transactions and capacity release transactions. See Part II, Item 7., "Comparison of Gas Distribution Operations—Business Segments Other than Local Gas Distribution—Gas Storage."

Other

We have other non-regulated investments, including assets in NNG Financial Corporation (Financial Corporation) (see "Subsidiaries," below), a Boeing 737-300 aircraft leased to Continental Airlines and miscellaneous other investments in non-regulated activities. Less than 1 percent of our consolidated assets and about 1 percent of 2006 consolidated net income are related to activities in the "Other" business segment.

Subsidiaries

Financial Corporation

We currently operate one direct, active subsidiary, Financial Corporation. Financial Corporation, a wholly-owned subsidiary incorporated in Oregon, holds financial investments including limited partnership interests in two wind power electric generation projects located in California and two low-income housing projects in Portland, Oregon. In January 2005, Financial Corporation sold its limited partnership interests in three solar electric generating plants located in California. Financial

Corporation also has one active, wholly-owned subsidiary, KB Pipeline Company (KB Pipeline), which owns a 10 percent interest in an 18-mile interstate natural gas pipeline. As a part owner of the pipeline, KB Pipeline is subject to certain regulations enacted by FERC with respect to the Standards of Conduct for Transmission Providers.

Gas Supply, Storage and Transportation Capacity

General

We meet the expected needs of our core utility customers through natural gas purchases from a variety of suppliers. Our supply and capacity plan is based on forecasted system requirements and takes into account estimated load growth by type of customer, attrition, conservation, distribution system constraints, interstate pipeline capacity and contractual limitations and the forecasted movement of customers between bundled sales service and transportation-only service. Sensitivity analyses are performed based on factors such as weather variations and price elasticity effects. We have a diverse portfolio of short-, medium- and long-term firm gas supply contracts that we supplement during periods of peak demand with gas from storage facilities either owned by or contractually committed to us.

Gas Acquisition Strategy

Our goals in purchasing gas for our core utility market consist of:

- ***Reliability***—Ensuring a gas resource portfolio that is sufficient to satisfy core utility customer requirements under design-day weather conditions, as defined in our Integrated Resource Plan (see "Regulation and Rates—Integrated Resource Plan," below);
- ***Lowest reasonable cost***—Applying strategies to acquire gas supplies at the lowest reasonable cost to utility customers;
- ***Price stability***—Making use of physical assets (e.g. gas storage) and financial instruments (e.g. financial hedge contracts such as price swaps) to manage price variability; and
- ***Cost recovery***—Managing gas purchase costs prudently to minimize the risks associated with regulatory review and recovery of gas acquisition costs.

To achieve those goals, we employ a gas purchasing strategy based upon a diversity of supply, liquidity, price risk management, asset optimization and regulatory alignment, as discussed in more detail below.

***Diversity of Supply***. There are three means by which we diversify our gas supply acquisitions: regional supply basin, contract types and contract duration.

The following table represents the actual and target purchase percentages from the regional sources of gas available to us:

Regional Supply Basin

| Region | 2006 Actual | 2006-2011 Target |
|---|---|---|
| Alberta | 41% | 45% |
| British Columbia | 29% | 30% |
| U.S. Rockies | 30% | 25% |
| Mist gas field | <1% | <1% |
| Total | 100% | 100% |

We believe that gas supplies available in the western United States and Canada are adequate to serve our core utility customers for the foreseeable future, and that our cost of gas generally will track market prices.

We typically enter into gas purchase contracts for:

- year-round baseload supply;
- November–March (winter heating season) baseload supply;
- winter heating season contracts where we have the option to call on all, some or none of the supplies on a daily basis; and
- spot purchases, taking into account forecasted customer requirements, storage injections and withdrawals and seasonal weather fluctuations.

Other less frequent types of contracts include April-October baseload contracts, April-October contracts where the supplier has the option to supply gas to us on a daily basis, and seasonal exchange purchase and sale contracts. In general, we try to maintain a diversified portfolio of purchase arrangements. For example, we use a variety of multi-year contract durations to avoid having to re-contract all supplies every year. See "Core Utility Market Basic Supply," below.

***Liquidity***. We purchase our gas supplies at liquid trading points to facilitate competition and price transparency. These trading points include the NOVA Inventory Transfer (NIT) point in Alberta (also referred to as AECO), Huntingdon/Sumas and Station 2 in British Columbia, and various receipt points in the Rocky Mountains.

***Price Risk Management.*** There are four general methods that we currently use for managing gas commodity price risk:

- negotiating fixed prices directly with gas suppliers;
- negotiating financial instruments that exchange the floating price in a physical supply contract for a fixed price (referred to as price swaps);
- negotiating financial instruments that set a ceiling and/or floor price on a floating price contract (referred to as call and put options, respectively); and
- buying gas and injecting it into storage. See "Cost of Gas," below.

***Asset Optimization***. We use our gas supply, storage and transportation flexibility to capture opportunities that emerge during the course of the year for gas purchases, sales, exchanges or other means to manage net gas costs. In particular, our Mist underground storage facility provides flexibility in this regard. In addition to our own activities to economically manage our gas supply costs, we contract with an independent energy marketing company to more fully capture optimization opportunities.

***Regulatory Alignment***. Mechanisms for gas cost recovery are designed to be fair and balanced for customers and shareholders. In general, we do not earn a return on the gas commodity purchased, and we attempt to minimize risks associated with cost recovery through:

- the use of purchased gas adjustment (PGA) mechanisms approved by the OPUC and WUTC (see "Regulation and Rates—Rate Mechanisms," below);
- aligning customer and shareholder interests through an incentive sharing mechanism for the PGA and asset optimization mechanisms; and
- periodic review of regulatory deferrals with state regulatory commissions and key customer groups.

Cost of Gas

The cost of gas to supply our core utility market primarily consists of the purchase price paid to suppliers, charges paid to pipelines to transport the gas to our distribution system and gains or losses related to hedge contracts entered into in connection with supply of gas to core customers. While the rates for pipeline transportation and storage services are subject to federal regulation, the purchase price of gas is not.

***Supply cost.*** Natural gas commodity prices increased dramatically over the last six years due to growing demand for natural gas, especially for power generation, stagnant North American gas production, surging alternative fuel prices, and the impact in 2005 of hurricane activity that affected oil and natural gas production in the Gulf of Mexico. We are in a favorable position with respect to gas production because of the proximity of our service territory to supply basins in western Canada and the Rocky Mountains, where some growth in gas production is expected to continue for the foreseeable future.

***Transportation cost.*** Pipeline transportation rates had been relatively stable in recent years, but two of the five major pipelines used by NW Natural filed for significant rate increases in 2006. Pipeline transportation rate increases are generally recoverable through our state-approved PGA mechanisms. See "Regulation and Rates—Interstate Pipeline Rate Cases," below.

***Hedging.*** We seek to mitigate the effects of higher gas commodity prices and price volatility on core utility customers by using our underground storage facilities strategically, by entering into natural gas commodity-based financial hedge contracts, and by crediting gas costs with margin revenues derived from off-system sales of commodity supplies and released transportation capacity in periods when core utility customers do not fully utilize firm pipeline transportation capacity and gas supplies.

Managing the Cost of Gas

We manage natural gas commodity price risk through an active hedging program in which we enter into either fixed price physical supply contracts or fixed price financial derivatives contracts. The financial contracts make up a majority of our commodity price hedging activity and these contracts are with a variety of investment-grade credit counterparties, typically with credit ratings of AA- or higher. See Part II, Item 7A., "Market Risk—Credit Risk—Credit exposure to financial derivative counterparties." Under this program, we enter into commodity swap, put and call option agreements for the coming year and up to three years into the future. Gains or losses from financial commodity hedge contracts are treated as reductions or increases to the cost of gas. The intended effect of this program is to lock in prices for a majority of our gas supply portfolio for the following gas contract year, including at least 50 percent of the expected heating season purchases, based on the market prices and forecasted purchase requirements prevailing at the time the financial agreements are entered into. Prices have been secured for less than 50 percent of gas purchases in subsequent gas contract years, but maintaining some longer term hedging in future years helps to stabilize future gas costs and reduces variations in annual customer rate changes.

In addition to the volumes for which prices are locked in through financial hedges, we also use gas storage as a physical hedge. We purchase and inject about 15 percent of our annual gas supply requirements into storage during the summer when gas prices are historically lower. That gas is stored for withdrawal during the winter months in five different storage facilities. We own and operate three of these storage facilities located within our service territory, which eliminates the need for additional upstream pipeline capacity and provides significant cost savings.

Source of Supply—Design Day Sendout

The effectiveness of our gas supply program ultimately rests on whether we provide reliable service at a reasonable cost to our core customers. To assure reliability, we base our plans on being able to meet the supply needs on the coldest weather experienced over the last 20 years in our service territory. We start with the coldest overall heating season and then modify it to include the coldest weather day over that same 20 year period. This coldest "design day" is the maximum anticipated demand on the natural gas distribution system during a 24-hour period, which currently assumes weather at an average temperature of 12 degrees Fahrenheit. We assume that all interruptible customers will be curtailed on the design day. Our projected sources of delivery for design day firm utility customer sendout total approximately 8.9 million therms. We are currently capable of meeting 63 percent of our firm customer design day requirements with storage and peaking supply sources located within or adjacent to our service territory. Optimal utilization of storage and peaking facilities on our design day reduces the dependency on firm transportation. On January 5, 2004, we experienced our current-record firm customer sendout of 7.2 million therms, and a total sendout of 8.9 million therms, on a day that was approximately 9 degrees Fahrenheit warmer than the design day temperature. That January 2004 cold weather event lasted about 10 days, and the actual firm customer sendout each day provided data indicating that load forecasting models required very little re-calibration. Accordingly, we believe that our supplies would be sufficient to meet firm customer demand if we are to experience design day conditions.

The following table reflects the sources of supply that are projected to be used to satisfy the design day sendout for the 2006-2007 winter heating season:

Projected Sources of Supply for Design Day Sendout

| Sources of Supply | Therms (in milions) | Percent |
|---|---|---|
| Firm Contracts | 3.25 | 37 |
| Off-system storage | 1.06 | 12 |
| Mist underground storage (utility only) | 2.30 | 26 |
| LNG storage | 1.80 | 20 |
| Recall agreements | 0.45 | 5 |
| Total | 8.86 | 100 |

We believe the combination of the natural gas supply purchases under contract, our peaking supplies and the transportation capacity held under contract on the interstate pipelines are sufficient to satisfy the needs of existing customers and are positioned to grow, as needed, to meet requirements in future years.

Core Utility Market Basic Supply

We purchase gas for our core utility customers from a variety of suppliers located in the western United States and Canada. As shown above, about 70 to 75 percent of our supply comes from Canada, with the balance coming primarily from the U.S. Rocky Mountain region. At January 1, 2007, we had 21 firm contracts with 10 suppliers and remaining terms ranging from three months to eight years, which provide for a maximum of 1.7 million therms of firm gas per day during the peak winter heating season and 1.2 million therms per day during the remainder of the year. These contracts have a variety of pricing structures and purchase obligations. During 2006, we purchased 833 million therms of gas under the following contract durations:

| Contract Duration (primary terms) | Percent of Purchases |
|---|---|
| Long-term (one year or longer) | 54% |
| Short-term (more than one month, less than a year) | 19% |
| Spot (less than one month) | 27% |
| Total | 100% |

We regularly renew or replace our expiring long-term gas supply contracts with new agreements from a variety of existing and new suppliers. Aside from the optimization of our core utility gas supplies by the independent energy marketing company (see "Gas Acquisition Strategy—Asset Optimization," above), four suppliers each amount to between 12.5 percent and 14.8 percent of our average daily contract volumes. Firm year-round supply contracts have remaining terms ranging from one to eight years. All term gas supply contracts use price formulas tied to monthly index prices, primarily at the NIT trading point in Alberta. We hedge a majority of these contracts each year using financial instruments as part of our gas purchasing strategy (see "Managing the Cost of Gas," above).

In addition to the year-round contracts, we continue to contract in advance for firm gas supplies to be delivered only during the winter heating season primarily under short-term contracts. During 2006, new short-term purchase agreements were entered into with four suppliers. These agreements have a variety of pricing structures and provide for a total of up to 500,000 therms per day during the 2006-2007 heating season. We intend to enter into new purchase agreements in 2007 for equivalent volumes of gas with our existing or other similar suppliers, as needed, to replace short-term and one-year contracts that will expire during 2007.

We also buy gas on the spot market as needed to meet demand. We have flexibility under the terms of some of our firm supply contracts enabling us to purchase spot gas in lieu of firm contract volumes, thereby allowing us to take advantage of favorable pricing on the spot market from time to time.

We continue to purchase gas from a non-affiliated producer in the Mist gas field in Oregon. The production area is situated near our underground gas storage facility. The price for this gas is tied to our weighted average cost of gas. Current production is approximately 10,000 therms per day from about 14 wells, supplying less than 1 percent of our total annual purchase requirements. Production from these wells varies as existing wells are depleted and new wells are drilled.

Core Utility Market Peaking Supply and Storage

We supplement our firm gas supplies with gas from storage facilities either owned or contractually committed to us. Gas is generally purchased and stored during periods of low demand for use during periods of peak demand. In addition to enabling us to meet our peak demand, these facilities make it possible to lower the annual average cost of gas by allowing us to minimize our pipeline transportation contract demand costs and to purchase gas for storage during the summer months when prices are historically lower.

***Underground storage.*** We have contracts with Northwest Pipeline Corporation (Northwest Pipeline) for firm gas storage services from an underground storage facility at Jackson Prairie near Chehalis, Washington, and an LNG facility at Plymouth, Washington. Together, these facilities provide us with daily firm deliverability of about 1.1 million therms and total seasonal capacity of about 16 million therms. Separate contracts with Northwest Pipeline provide for the transportation of these storage supplies to our service territory. All of these contracts have reached the end of their primary terms, but we have exercised our renewal rights that allow for annual extensions at our option.

We also provide daily and seasonal peaking from our underground gas storage facility in the Mist gas field. Including the latest expansions in 2005, this facility has a maximum daily deliverability of 4.4 million therms and a total working gas capacity of about 14 Bcf. In September 2004, we completed our South Mist pipeline extension project, which is a utility transmission pipeline from our Mist gas storage field to growing portions of our distribution service area. Also in 2004, a total of 400,000 therms per day of Mist storage capacity, which had been available for the non-utility gas storage business, was recalled and committed to use for core utility customers. This was the first instance of returning capacity that had been developed in advance of core utility customers' needs for interstate gas storage services under the regulatory agreement with the OPUC. Under this agreement, storage capacity is recalled as needed and added to utility rate base, at our original cost less accumulated depreciation, with a corresponding rate increase to customers to reflect the cost of service. No additional recalls of Mist capacity were required in 2005 or 2006. The core utility market now has 2.3 million therms per day of deliverability and approximately 9 Bcf of working gas committed from the Mist storage facility.

In December 2005, we completed our latest expansion of the Mist gas storage facility. This investment increased the facility's incremental capacity and total daily delivery capacity. All of this expansion is currently being used to serve growth in the gas storage market. Ultimately, this expansion also will be available to serve the needs of our core utility customers. The expansion increased working gas capacity at Mist to about 14 Bcf, with 5 Bcf allocated to the gas storage business segment. As the needs of core utility customers grow, existing storage capacity will be recalled and transferred for use by core utility customers and tracked into customer rates. As storage capacity is recalled to serve core utility customers, new storage capacity can be developed. Additional expansion at Mist is currently underway for customer use in 2007.

***LNG.*** We own and operate two LNG plants in our service territory that liquefy gas during the summer months for storage until the peak winter heating season. These two plants provide a maximum combined daily deliverability of 1.8 million therms and a total seasonal capacity of 17 million therms.

***Recallable capacity.*** We also have contracts with one electric generator and two industrial customers that together provide an additional 52,000 therms per day of year-round upstream capacity, plus 450,000 therms per day of recallable capacity and supply. Two of these three contracts renew from year to year, while the third will expire in 2010.

Transportation

***Dependence on a Single Transportation Pipeline***. Our distribution system is directly connected to a single interstate pipeline, Northwest Pipeline. Although we are dependent on a single pipeline, the pipeline is bi-directional as it transports gas into the Portland metropolitan market from two directions: (1) the north, which brings supplies from British Columbia and Alberta supply basins; and (2) the east, which brings supplies from Alberta as well as the Rocky Mountain supply basins. The need for pipeline transportation diversity has been underscored by past Northwest Pipeline ruptures and the resulting federal order in 2003 that required Northwest Pipeline to replace its 26-inch mainline from the Canadian border to our service territory. That replacement project was completed by Northwest Pipeline in November 2006. We are pursuing options to further diversify our pipeline transportation paths. Specifically, we are currently evaluating a potential pipeline project that would connect TransCanada Pipelines Limited's (TransCanada) Gas Transmission Northwest (GTN) interstate transmission line to our gas distribution system. This project could provide an alternate transportation path for gas purchases in Alberta that currently move through the Northwest Pipeline system.

***Rates.*** Rates for pipeline transportation are established by FERC for service under long-term transportation agreements with the U.S. interstate pipelines and by Canadian federal or provincial authorities for service under agreements with the Canadian pipelines over which we ship gas.

***Transportation Agreements***. The largest of our transportation agreements with Northwest Pipeline extends through 2013 and provides for firm transportation capacity of up to 2.1 million therms per day. This agreement provides access to natural gas supplies in British Columbia and the U.S. Rocky Mountains.

Our second largest transportation agreement with Northwest Pipeline extends through 2011. It provides 1.0 million therms per day of firm transportation capacity from the point of interconnection of the Northwest Pipeline and GTN systems in eastern Oregon to our service territory. GTN's pipeline runs from the U.S./Canadian border through northern Idaho, southeastern Washington and central Oregon to the California/Oregon border. We have firm long-term capacity on GTN and two upstream pipelines in Canada, which, with GTN, are business units of TransCanada, to match this amount of Northwest Pipeline capacity northward into Alberta, Canada.

We also have an agreement with Northwest Pipeline that extends through 2013 for approximately 350,000 therms per day of firm transportation capacity. This agreement accesses gas supplies in the U.S. Rocky Mountain region.

In addition, we have firm long-term pipeline transportation contracts with two other major transporters. A contract with Duke Energy Gas Transmission (formerly Westcoast Energy, Inc.) extends through October 2014 and provides approximately 600,000 therms per day of firm gas transportation from Station 2 in northern British Columbia to the Huntingdon/Sumas connection with Northwest Pipeline at the U.S./Canadian border. A contract with Terasen Gas extends through October 2020 and provides approximately 470,000 therms per day of firm gas transportation from southeastern British Columbia to the same Huntingdon/Sumas connection with Northwest Pipeline. Our capacity with Terasen Gas is matched with companion contracts for pipeline capacity on the TransCanada BC System and NOVA system in British Columbia and Alberta, allowing purchases to be made from the gas fields of Alberta, Canada. See "Regulation and Rates—Interstate Pipeline Rate Cases," below.

Regulation and Rates

We provide local distribution gas utility service in Oregon and Washington and, accordingly, we are subject to state regulation with respect to, among other matters, rates, systems of accounts and issuance of securities by the OPUC and the WUTC. Local distribution service in Oregon represents over 90 percent of the utility's revenues.

NW Natural is exempt from FERC jurisdiction under Sections 1(b) and 1(c) of the Natural Gas Act (the Hinshaw exemption). We provide FERC-regulated storage services to interstate customers pursuant to a limited jurisdiction certificate from FERC.

General Rate Cases

Our most recent general rate increase in Oregon authorized rates designed to produce a return on shareholders' equity (ROE) of 10.2 percent and was effective September 1, 2003. Our most recent general rate case in Washington authorized a revenue increase of $3.5 million per year but did not specifically authorize an ROE and was effective July 1, 2004.

In May 2005, we reached a settlement with the FERC staff and all intervenors with respect to our rate case filed in January 2005 related to Mist interstate storage service. The settlement provided for a small net increase in the maximum rates for our interstate storage. These new maximum rates are designed to reflect updated costs related to development of the Mist gas storage facility since 2001 and costs associated with the South Mist pipeline extension project. The new rates were effective July 1, 2005.

Rate Mechanisms

***Purchased Gas Adjustment***. Rate changes are applied each year under the PGA tariff mechanisms in Oregon and Washington to reflect changes in the total costs of natural gas commodity. The OPUC and the WUTC approved rate increases on October 25, 2006 that became effective on November 1, 2006, compared to October 1 in the prior year. The effect of the rate changes was to increase the average monthly bills of Oregon residential sales customers by 3.5 percent and those of Washington residential sales customers by 2.6 percent.

Under the current PGA mechanisms, we collect an amount for purchased gas costs based on estimates included in rates. If the actual purchased gas costs differ from the amounts included in rates, we are required to defer a majority of that difference and pass it on to customers as an adjustment to future rates. As part of an incentive mechanism in Oregon, the utility recognizes in current earnings either a charge to expense for 33 percent of the higher cost of gas sold, or a credit to expense for 33 percent of the lower cost of gas sold. In Washington, the PGA deferral is 100 percent of the higher or lower actual cost of gas sold.

In October 2006, the OPUC approved a modification to our PGA tariff, effective November 1, 2006, which provides that we use actual recoveries of gas costs in revenues billed (instead of using estimated gas costs incorporated in rates) compared to actual purchased gas costs to determine our PGA deferral. The effect of the new method is that changes in our line loss expense due to changes in unaccounted for gas volumes are deferred and included in the annual PGA mechanism. However, consistent with our prior PGA sharing mechanism, 67 percent of any cost differences for Oregon volumes is deferred for refund or recovery in customer rates in subsequent periods, while the remaining 33 percent is included in current earnings.

The OPUC has begun a formal review of the PGA process, which will cover portfolio requirements, incentive sharing levels and filing requirements, among other items. The investigation is expected to be completed in early 2008. Implementation of any changes to the PGA mechanism is expected in the 2008 PGA filing.

***Conservation Tariff***. In October 2002, the OPUC authorized the implementation of a "conservation tariff," which is a rate mechanism designed to adjust margin for changes in average consumption patterns due to residential and commercial customers' conservation efforts. The tariff is a partial decoupling mechanism that is intended to break the link between earnings and the quantity of gas consumed by customers, removing any incentive for the utility to discourage customers' conservation efforts. On average, residential and commercial customers have continued to reduce energy consumption over the past several years in response to the impact of higher energy prices on their utility bills and an increased awareness of energy efficiency measures and programs. In Washington, customer use is not covered by a conservation tariff, and as such our utility earnings are affected by increases and decreases in usage based on customers' conservation efforts. Washington customers account for about 10 percent of utility revenues.

The Oregon conservation tariff includes two components: (1) a price elasticity adjustment, which adjusts rates annually for expected increases or decreases in customer volumes due to annual changes in commodity costs or periodic changes in our general rates; and (2) a conservation adjustment calculated on a monthly basis to account for deviations between actual and expected volumes (also referred to as the decoupling adjustment). The margin adjustment resulting from differences between actual and expected volumes under the decoupling component is recorded to a deferral account, which is included in the next year's annual PGA. Baseline consumption was determined by customer consumption data used in the 2003 Oregon general rate case, adjusted for new customers. See Part II, Item 7., "Results of Operations—Comparison of Gas Distribution Operations."

In 2005, an independent study to measure the Oregon tariff mechanism's effectiveness recommended continuation of the conservation tariff with minor modifications. In 2005 and 2006, the OPUC approved the continuation of the conservation tariff through September 30, 2009 and increased the mechanism's coverage from a partial decoupling of 90 percent of residential and commercial gas usage to a full decoupling of 100 percent.

***Weather Normalization***. In November 2003, the OPUC authorized, and the utility implemented, a weather normalization mechanism in Oregon that helps stabilize utility margins by adjusting residential and commercial customer billings based on temperature variances from average weather. The current normalization mechanism is applied to our residential and commercial customers' bills between December 1 and May 15 for each heating season. The mechanism adjusts the margin component of customers' rates to reflect "average" weather using the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers. We do not have a weather normalization mechanism approved for our Washington customers, which account for about 10 percent of our utility revenues.

***Excess Earnings Test.*** The OPUC's annual formal review process to test for excess earnings ensures that we are allowed to pass through 100 percent of prudently incurred gas costs into rates. We are subject to an excess earnings test requirement in which we retain all of our earnings up to a threshold level equal to our authorized ROE of 10.2 percent plus 300 basis points. Revenues equivalent to 33 percent of any earnings above the threshold are required to be refunded to customers. The excess earnings threshold is subject to adjustment up or down each year based on movements in long-term interest rates. In 2006 and 2005, the threshold after adjustment was 13.44 percent and 13.32 percent, respectively. No amounts were required to be refunded to customers as a result of the 2005 or 2004 earnings test. We do not expect any amounts to be refunded to customers as a result of the 2006 earnings test, which will be reviewed by the OPUC during the second quarter of 2007. In Washington, we are not subject to an annual excess earnings test, and 100 percent of all prudently incurred gas costs are passed through into customer rates.

***Recent Changes in Industrial Tariffs.*** In August 2006, the OPUC and WUTC approved tariff changes to the service options for our major industrial accounts. The changes set out additional parameters to provide more certainty in the level of gas supplies we will need to acquire to serve this customer group. The parameters include an annual election period, special pricing provisions for out-of-cycle changes and a requirement that customers on our annual weighted average cost of gas tariff complete the term of their service election.

***Pipeline Integrity Cost Recovery***. In July 2004, the OPUC approved our application relating to the accounting treatment and full recovery for the cost of the pipeline integrity management program, as mandated by the Pipeline Safety Improvement Act of 2002 and related rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration. The accounting and rate treatment for these costs extends through September 30, 2008 and may be reviewed for potential extension after that date. We do not have any special accounting or rate treatment for pipeline integrity costs incurred in the state of Washington.

Interstate Pipeline Rate Cases

On June 30, 2006, the two interstate pipeline companies that provide natural gas transportation to our distribution system filed general rate increase cases with the FERC. See Part II, Item 7., "Results of Operations—Regulatory Matters—Interstate Pipeline Rate Cases". Increases in interstate pipeline transportation expenses are subject to our PGA deferral mechanism and are 100 percent passed-through to customers in both Oregon and Washington. Pipeline transportation demand charges are not subject to the 33 percent incentive sharing mechanism in Oregon. Both of these increases in pipeline transportation rates were included in our 2006 PGA rates. In February 2007, Northwest Pipeline filed a settlement proposal with the FERC that would resolve all issues with the active parties and would result in an increase in our transportation rates of about $12.0 million. Amounts collected from our utility customers in excess of this settlement amount will be deferred and returned to customers in our next PGA rate filing in late 2007.

Integrated Resource Plan

The OPUC and WUTC have implemented integrated resource planning processes under which utilities develop plans defining alternative growth scenarios and resource acquisition strategies. Our most recent integrated resource plan was filed in Oregon and Washington in 2005. Elements of the plan included:

- an evaluation of supply and demand resources;
- the consideration of uncertainties in the planning process and the need for flexibility to respond to changes;
- a primary goal of "least cost" service; and
- consistency with state energy policy.

Although the OPUC's order acknowledging the integrated resource plan does not constitute ratemaking approval of any specific resource acquisition or expenditure, the OPUC generally indicates that it would give considerable weight in prudency reviews to utility actions that are consistent with acknowledged plans. Elements of our draft integrated resource plan demonstrate that the continued development of the Mist underground gas storage facility is the least-cost option for serving customer growth. We expect to file an updated plan in 2007.

Additions to Infrastructure

We expect a high level of capital expenditures for additions to infrastructure over the next five years, reflecting projected customer growth, technology, system replacement, improvement and reinforcement projects and the development of additional gas storage facilities. Estimated capital expenditures in 2007 total about $110 million, and for the years 2007-11 capital expenditures are estimated at between $500 and $600 million. We continue to be one of the fastest growing gas utilities in the nation (see "Competition and Marketing," below). In 2006, our customer base grew by more than 3 percent for the 20th year in a row.

Pipeline Safety

The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (2006 Act) was signed into law in December 2006. The 2006 Act mandates certain standards related to our distribution lines, including a development of integrity management programs for those distribution pipelines. We do not anticipate any material impacts during 2007, but do expect changes related to the 2006 Act to begin to impact us in 2008.

The Pipeline Safety Improvement Act of 2002 (Act) and related regulations require gas transmission pipeline operators to identify lines located in High Consequence Areas (HCAs) and develop integrity management programs 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 and related pipeline safety regulations require us to complete inspection of 50 percent of the highest risk pipelines located in our HCAs within the first five years, and the remaining covered pipelines within 10 years, of the date of enactment. We are also required to re-inspect the covered pipelines every seven years from the date of the previous inspection for the life of the pipelines. We have met the first major milestone required by the Act and are on track to complete the next milestone, which is to complete the inspection of 50 percent of our highest risk transmission pipelines by the end of 2007.

Effective January 12, 2005, we assumed responsibilities as operator of an approximately 60-mile pipeline that transports gas from Northwest Pipeline to Coos County, Oregon. The pipeline is owned by Coos County, and we have an agreement to operate the pipeline and related lateral pipelines that runs yearly until terminated by either party. The pipeline safety requirements of the Act apply to us as operator of that pipeline.

In 2001, we entered into a stipulation with the OPUC for an enhanced pipeline safety program that includes an accelerated bare steel replacement program and a geo-hazard safety program. The bare steel program accelerates the replacement of our bare steel piping over 20 years instead of 40 years and allows us to receive rate treatment for costs associated with the program exceeding $3 million per year. The geo-hazard component of the safety program expired on December 31, 2006. It included the identification, assessment and remediation of risks to piping infrastructure created by landslides, washouts, earthquakes or similar occurrences, and allowed us to receive deferred rate treatment for costs associated with the program. Although the regulatory authority for the geo-hazard safety program expired, we received approval from the OPUC to defer the costs up to $2.5 million associated with a specific remediation project, which is expected to be completed in 2007.

Competition and Marketing

Competition with Other Energy Products

We have no direct competition in our service area from other natural gas distributors. However, for residential customers' heating needs, we compete with 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, including gas-to-gas competition from third-party sellers of natural gas commodity. Competition among these forms of energy is based on price, reliability, efficiency and performance.

The slight competitive price advantage of natural gas over electricity was maintained in 2006 as natural gas commodity prices began to moderate and electricity prices remained stable in both the residential and commercial markets. The current price advantage varies due to differences in retail electric rates between investor-owned utilities, where we have maintained a moderate price advantage, and public utilities, where our price advantage, if any, is marginal. In 2006, although electricity prices continued to become more competitive primarily due to higher gas prices and improving end use technology for heat pumps, natural gas retained its relative price advantage compared to electricity provided by the investor-owned utilities that serve approximately 75 percent of the homes in our Oregon service area. We expect to maintain a price advantage compared to electricity from the investor-owned electric utilities in part because a growing portion of the electricity sold by these utilities is generated using natural gas.

Residential and Commercial Markets

The relatively low market saturation of natural gas in residential single-family dwellings in our service territory, estimated at approximately 50 percent, together with the price advantage of natural gas compared with electricity in most areas and our operating convenience over fuel oil, provides the potential for continuing growth from residential and commercial conversions. In 2006, 18,449 net residential customers (after subtracting disconnected or terminated services) were added, primarily from single- and muti-family new construction, but also included existing residential housing that converted from oil, electric or propane appliances to natural gas. The net increase of all new customers added in 2006 was 19,421. This represents a growth rate of 3.1 percent, which is about twice the national average for local gas distribution companies as reported by the American Gas Association.

Industrial Markets

As a result of the deregulation and restructuring of the energy markets during the past two decades, the natural gas industry, including producers, interstate pipelines and local gas distribution companies, has undergone significant changes. Traditionally, local gas distribution companies sold a “bundled” product that included both the natural gas commodity and delivery to the end-use customer’s meter. However, beginning in the late 1980s, large industrial customers sought to achieve savings by procuring their own supplies of natural gas from producers and contracting with pipelines and local gas distribution companies for transportation of natural gas to their facilities. These changes were intended to promote competition where it was economically beneficial to consumers.

Competition to serve the industrial and large commercial market in the Pacific Northwest has been relatively steady since the early 1990s in terms of numbers and types of competitors. Competitors consist of gas marketers, oil/propane sellers and electric utilities. Wood-based fuels continue to lose market share in these markets primarily due to environmental concerns and restrictions.

The OPUC and WUTC have approved transportation tariffs under which we may contract with customers to deliver customer-owned gas. Transportation tariffs available to industrial customers are priced at our cost of providing transportation service. Generally, we are unaffected financially if industrial customers transport customer-owned gas rather than purchasing gas directly from us, as long as they remain on a tariff or contract with the same quality of service. This is because we do not generally make any margin on the sale of the gas commodity. However, industrial customers may select between firm and interruptible service, among other different levels or qualities of service, and these choices can positively or negatively affect margin. The relative level and volatility of prices in the natural gas commodity markets, the availability of interstate pipeline capacity to ship customer-owned gas and the cost structure embedded in our industrial rates are among the primary factors that have caused some industrial customers to alternate between sales and transportation service or between higher and lower qualities of service.

We redesigned our industrial rates in Oregon and Washington as part of our general rate cases in 2003 and 2004, respectively, in order to better reflect relative costs of service and to become more competitive in the industrial market. In August 2006, the OPUC and WUTC approved further tariff changes to the service options for our industrial accounts. The changes set out additional parameters that give us more certainty in the level of gas supplies we will need to purchase in order to serve this customer group. The parameters include an annual election cycle period, special pricing provisions for out-of-cycle changes and the requirement that customers on our annual weighted average cost of gas tariff complete the agreed upon term of their service. In the case of customers switching out-of-cycle from transportation to sales service, the customer will be charged the cost of incremental gas supply under our regulatory tariff.

We have negotiated special transportation service agreements with some of our largest industrial customers. These special agreements are designed to provide transportation rates that are competitive with the customer's alternative capital and operating costs of installing direct connections to Northwest Pipeline's interstate pipeline system, which would allow them to bypass our gas distribution system. These agreements generally prohibit bypass during their terms. Due to the cost pressures that confront a number of our largest customers competing in global markets, bypass continues to be a threat. Although we do not expect a significant number of our large customers to bypass our system in the foreseeable future, we may experience further deterioration of margin associated with customers' transfers to contracts with pricing designed to be competitive with bypass.

## Environmental Issues

### Properties and Facilities

We have properties and facilities that are subject to federal, state and local laws and regulations related to environmental matters. These evolving laws and regulations may require expenditures over a long timeframe to control environmental effects. Estimates of liabilities for environmental response costs are difficult to determine with precision because of the various factors that can affect their ultimate level. These factors include, but are not limited to, the following:

- the complexity of the site;
- changes in environmental laws and regulations at the federal, state and local levels;
- the number of regulatory agencies or other parties involved;
- new technology that renders previous technology obsolete, or experience with existing technology that proves ineffective;
- the ultimate selection of a particular technology;
- the level of remediation required; and
- variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site.

We own or previously owned properties currently being investigated that may require environmental response, including a property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (Gasco site), a property adjacent to the Gasco site that is now the location of a manufacturing plant owned by Siltronic Corporation (Siltronic site), and an area adjacent to the Gasco and the Siltronic sites along a segment of the Willamette River that has been listed by the U.S. Environmental Protection Agency as a Superfund site for which we have been identified as one of a number of potentially responsible parties (Portland Harbor site). We do not expect that the ultimate resolution of these matters will have a material adverse effect on our financial condition or results of operations; however, if it is determined that both the insurance recovery and future rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made and could have a material impact on our financial condition or results of operations. See Part II, Item 8, Note 12, to the accompanying Consolidated Financial Statements for a further discussion of potential environmental responses and related costs.

Future Environmental Issues

We recognize that our business is likely to face future carbon constraints. A variety of legislative and regulatory measures to address greenhouse gas emissions are in various phases of discussion or implementation. These include the proposed international standards (Kyoto Protocol), proposed federal legislation and proposed or enacted state actions to develop statewide or regional programs, each of which have imposed or would impose reductions in greenhouse gas emissions. The outcome of federal and state climate change initiatives cannot be determined at this time, but these initiatives could result in a variety of regulatory programs including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could result in increased costs associated with operating and maintaining our facilities, could increase other costs to our business and could impact the prices we charge our customers. Because natural gas is a fossil fuel with a low carbon content, it is possible that future carbon constraints could create additional demand for natural gas, both for electric production and direct use in homes and businesses. We have actively participated in policy development through the Oregon Governor's Task Force on Climate Change and are leading efforts within the American Gas Association to promote the enactment of fair climate change legislation. We recently created an Environmental Policy and Sustainability Department with responsibility for engaging in policy development and identifying ways to reduce greenhouse gas emissions associated with our operations.

## Employees

At December 31, 2006, we had 1,211 employees, of which 815 were members of the Office and Professional Employees International Union (OPEIU), Local No. 11, AFL-CIO. We have a labor agreement (Joint Accord) with members of OPEIU covering wages, benefits and working conditions that will expire on May 31, 2009.

## Available Information

We file annual, quarterly and special reports and other information with the Securities and Exchange Commission (SEC). We make available on our website (http://www.nwnatural.com), free of charge, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports, as well as proxy materials, filed or furnished pursuant to Section 13(a) or 15(d) and Section 14 of the Securities Exchange Act of 1934, as amended (Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

We have adopted a Code of Ethics for all employees and a Financial Code of Ethics that applies to senior financial employees, both of which are available on our website. Our Corporate Governance Standards, Director Independence Standards, charters of each of the committees of the Board of Directors and additional information about us are also available on the website.

Copies of these documents may be requested, at no cost, by writing or calling Shareholder Services, NW Natural, One Pacific Square, 220 N.W. Second Avenue, Portland, Oregon 97209, telephone 503-226-4211.

Our Chief Executive Officer certified to the New York Stock Exchange (NYSE) on June 13, 2006 that, as of that date, he was not aware of any violation by the company of NYSE's corporate governance listing standards, and that we had filed with the SEC, as exhibits 31.1 and 31.2 to our Annual Report on Form 10-K for the year ended December 31, 2005, the certificates of the Chief Executive Officer and the Chief Financial Officer certifying the quality of NW Natural's internal control over financial reporting and public disclosures. For the year-ended December 31, 2006, the certificates of the Chief Executive Officer and the Chief Financial Officer are filed with this report as Exhibits 31.1 and 31.2.

ITEM 1A. RISK FACTORS

Our 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 SEC.

***Regulatory risk.*** *The rates we charge customers for gas distribution services are established by the OPUC and the WUTC. The 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 the utility resells gas to its customers or transports gas owned by large customers from the interstate pipeline connection to the customers' facilities must be approved by the OPUC or the WUTC. 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 OPUC or the WUTC 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.

***Gas prices.*** *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 and in Washington, the utility has PGA tariffs which provide for annual revisions in rates resulting from changes in the cost of purchased gas. The Oregon PGA tariff provides that 33 percent of any difference between the actual purchased gas costs and the actual recoveries of gas costs in rates be recognized as current income or expense. Accordingly, higher gas costs than those assumed in setting rates can adversely affect our results of operations.

The OPUC has begun a formal review of the PGA process which will cover portfolio requirements, incentive sharing levels and filing requirements, among other items. The investigation is expected to be completed in early 2008. Implementation of any changes to the PGA mechanism is expected in the 2008 PGA filing.

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

***Business risk.*** *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, which could adversely affect our financial condition and results of operations.

***Customer conservation.*** *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 conservation tariff expires in September 2009. The failure of the OPUC to extend the conservation tariff in the future could adversely affect our financial condition and results of operations. We do not have a conservation tariff in Washington.

***Environmental risks.*** *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. Also, management expects that future legislation may impose carbon constraints to address global climate change.*

We own, or previously owned, properties that require environmental remediation or other action. We accrue all material loss contingencies relating to these properties, but our results of operations may be adversely affected to the extent that estimates of the probable costs increase significantly as additional information becomes available and to the extent we are not able to recover the incremental cost through customer rates or from insurance. A regulatory asset has already been recorded for some of these estimated costs. To the extent we are unable to recover these costs in rates or through insurance, then we would be required to reduce our regulatory asset which could adversely affect our results of operations and financial condition.

We cannot predict with certainty the amount or timing of future expenditures related to any environmental investigation and remediation that may be required because of the difficulty of estimating such costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. There are also no assurances that existing environmental regulations will not be revised or that new stricter regulations seeking to protect the environment will not be adopted or become applicable to us. Revised environmental regulations which result in increased compliance costs or additional operating restrictions could have a material adverse effect on our results of operations, particularly if those costs are not fully recoverable from customers.

There are a number of legislative and regulatory proposals to address greenhouse gas emissions, which are in various phases of discussion or implementation. The outcome of federal and state actions to address global climate change could result in a variety of regulatory programs including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could result in increased costs associated with operating and maintaining our facilities, could increase other costs to our business and could impact the prices we charge our customers.

***Competition.*** *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 suppliers of electricity and fuel oil for commercial applications. In the industrial market, we compete with all forms of energy suppliers. 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.

***Single transportation pipeline.*** *We rely on a single pipeline for the transportation of gas to our service territory.*

We are largely dependent on a single, bi-directional pipeline for transportation of gas into our service territory. Our results of operations may be negatively impacted if there is a rupture in the pipeline and we incur costs associated with actions taken to mitigate disruption of service.

***Pension funding.*** *The cost of providing pension and other postretirement benefit plans is subject to changes in assumptions, fluctuations in the market value of plan assets and changes in demographics, all of which may have a material effect on our results of operations and cash flows.*

We maintain two qualified non-contributory defined benefit pension plans, several non-qualified supplemental pension plans and other postretirement benefit plans. We may be required to recognize a material increase or decrease in annual pension or postretirement benefit expense based on changes in assumed interest rates, market returns, expected rate of wage increases and other factors, and we may be required to record a charge to our balance sheet to the extent that projected benefit obligations exceed the fair value of plan assets.

***Operating risk.*** *Transporting and storing 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 operating hazards and risks, such as leaks, accidents, mechanical problems, fires, storms, landslides and other adverse weather conditions and hazards, 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.

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

A large portion of the utility's margin is derived from sales to space heating residential and commercial customers during each winter heating season. Current rates are based on an assumption of average weather. In Oregon, the effects of warmer or colder weather on utility margin are reduced through the operation of our weather normalization mechanism and conservation tariff. However, 9 percent of eligible customers elected not to be covered by the weather normalization mechanism. Also, approximately 10 percent of our residential and commercial customers are in Washington where we do not have a weather normalization mechanism or conservation tariff. As a result, we are not fully protected against warmer than average weather, which may have an adverse affect on our financial condition, results of operations and cash flows.

***Workforce risk***. *Our business is heavily dependent on being able to attract and retain qualified employees and to maintain a competitive cost structure with market-based salaries and employee benefits.*

Our gas distribution business is subject to a variety of workforce risks, including being able to attract and retain qualified employees, being able to transfer the knowledge and expertise of an aging workforce to new employees as older workers retire and being able to reach collective bargaining agreements with the union that represents about 70 percent of our workers.

***Customer growth.*** *Our results of operations may be negatively affected by our ability to sustain customer growth.*

Our earnings growth and results of operations have largely been dependent upon the sustained growth of our residential and commercial customer base at an annual rate of over 3 percent. If we are unable to sustain these levels of customer growth, our results of operations may be negatively affected. A number of factors could negatively impact our ability to sustain growth, such as a downturn in the economy, reduced housing starts and competition.

## ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

## ITEM 2. PROPERTIES

Our natural gas distribution system consists of 13,474 miles of distribution and transmission mains located in our service territory in Oregon and Washington. In addition, the distribution system includes service pipes, meters and regulators, and gas regulating and metering stations. The mains are located in municipal streets or alleys pursuant to valid franchise or occupation ordinances, in county roads or state highways pursuant to valid agreements or permits granted pursuant to statute, or on lands of others pursuant to valid easements obtained from the owners of such lands. We also hold all necessary permits for the crossing of the Willamette River and a number of smaller rivers by our mains.

We own service facilities in Portland, as well as various satellite service centers, garages, warehouses and other buildings necessary and useful in the conduct of our business. We lease office space in Portland for our corporate headquarters, which lease expires on May 31, 2018. District offices are maintained on owned or leased premises at convenient points in the distribution system. We own LNG storage facilities in Portland and near Newport, Oregon.

We hold interests in 8,624 net acres of underground natural gas storage and 1,780 net acres of oil and gas leases in Oregon. We own rights to depleted gas reservoirs near Mist, Oregon, that are continuing to be developed as underground gas storage facilities. We also hold an option to purchase future storage rights in certain other areas of the Mist gas field.

In order to reduce risks associated with gas leakage in older parts of our system, we undertook an accelerated pipe replacement program under which we removed or replaced 100 percent of our cast iron mains by October 2000. In 2001, we initiated an accelerated pipe replacement program under which we will reduce the amount of bare steel mains in the system.

We consider all of our properties currently used in our operations, both owned and leased, to be well maintained, in good operating condition, and, along with planned additions, adequate for our present and foreseeable future needs.

Our Mortgage and Deed of Trust is a first mortgage lien on substantially all of the property constituting our utility plant.

## ITEM 3. LEGAL PROCEEDINGS

See Note 12 to Consolidated Financial Statements, "Commitments and Contingencies—Legal Proceedings."

## ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

There were no matters submitted to a vote of security holders, through the solicitation of proxies or otherwise, during the quarter ended December 31, 2006.

PART II

## ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

(A) Our common stock is listed and trades on the New York Stock Exchange under the symbol "NWN."

The high and low trades for our common stock during the past two years were as follows:

| Quarter Ended | 2006 High | 2006 Low | 2005 High | 2005 Low |
|---|---|---|---|---|
| March 31 | $36.57 | $32.83 | $37.24 | $32.42 |
| June 30 | 37.04 | 33.30 | 38.67 | 34.36 |
| September 30 | 40.08 | 35.81 | 39.63 | 35.60 |
| December 31 | 43.69 | 38.53 | 37.77 | 33.25 |

The closing quotations for our common stock on December 29, 2006 and December 30, 2005 were $42.44 and $34.18, respectively.

(B) As of December 31, 2006, there were 8,753 holders of record of our common stock.

(C) We have paid quarterly dividends on our common stock in each year since the stock first was issued to the public in 1951. Annual common dividend payments have increased each year since 1956. Dividends per share paid during the past two years were as follows:

| Payment Date | 2006 | 2005 |
|---|---|---|
| February 15 | $0.345 | $0.325 |
| May 15 | 0.345 | 0.325 |
| August 15 | 0.345 | 0.325 |
| November 15 | 0.355 | 0.345 |
| Total per share | $1.390 | $1.320 |

The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. It is the intention of the Board of Directors to continue to pay cash dividends on our common stock on a quarterly basis. However, the declaration and amount of future dividends will be dependent upon our earnings, cash flows, financial condition and other factors.

(D) The following table provides information about purchases of our equity securities that are registered pursuant to Section 12 of the Exchange Act during the quarter ended December 31, 2006:

ISSUER PURCHASES OF EQUITY SECURITIES

| Period | (a) Total Number of Shares Purchased (1) | (b) Average Price Paid per Share | (c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (2) | (d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (2) |
|---|---|---|---|---|
| Balance forward | | | 812,700 | $60,260,697 |
| 10/01/06-10/31/06 | 1,380 | $40.27 | 70,000 | (2,851,596) |
| 11/01/06-11/30/06 | 22,576 | $40.90 | 113,400 | (4,571,685) |
| 12/01/06-12/31/06 | 1,742 | $42.72 | 165,000 | (6,937,500) |
| Total | 25,698 | | 1,161,100 | $45,899,916 |

(1) During the quarter ended December 31, 2006, 24,901 shares of our common stock were purchased in the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan (DSPP). In addition, 797 shares of our common stock were purchased in the open market during the quarter under equity-based programs. During the three months ended December 31, 2006, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) On May 25, 2000, we announced a program to repurchase up to 2 million shares, or up to $35 million in value, of our common stock through a repurchase program that has been extended annually. In April 2006, the Board extended the program through May 31, 2007 and increased the authorization from 2 million shares to 2.6 million shares and increased the dollar limit from $35 million to $85 million. Share repurchases are made in the open market or through privately negotiated transactions. During the three months ended December 31, 2006, 348,400 shares of our common stock were purchased pursuant to this program. Since the program's inception, we have repurchased 1,161,100 shares of common stock at a total cost of $39.1 million.

On September 29, 2006, we entered into a Stock Purchase Plan Engagement Agreement with our broker in order to establish a trading plan for our repurchase program that qualifies for the safe harbors provided by Rule 10b-18 and Rule 10b5-1 under the Securities Exchange Act of 1934, as amended. The agreement expired on December 31, 2006.

## ITEM 6. SELECTED FINANCIAL DATA

| Thousands, except per share amounts and ratio of earnings to fixed charges | For the year ended Dec. 31, 2006 | 2005 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|
| Utility operating revenues: | | | | | |
| Residential sales | $ 536,468 | $ 471,502 | $ 383,067 | $ 328,346 | $ 354,735 |
| Commercial sales | 290,666 | 250,287 | 200,424 | 176,336 | 201,475 |
| Industrial - firm sales | 66,986 | 64,507 | 45,259 | 33,578 | 42,965 |
| Industrial - interruptible sales | 93,107 | 100,740 | 55,380 | 23,655 | 15,937 |
| Unbilled revenues[1] | - | - | - | 14,474 | (12,702) |
| Total gas sales revenues | 987,227 | 887,036 | 684,130 | 576,389 | 602,410 |
| Transportation | 12,800 | 10,755 | 12,655 | 17,968 | 26,020 |
| Other | 161 | 2,862 | 4,160 | 7,627 | 4,018 |
| Total gross utility operating revenues | 1,000,188 | 900,653 | 700,945 | 601,984 | 632,448 |
| Cost of gas sold | 648,081 | 563,772 | 399,176 | 323,128 | 353,034 |
| Revenue taxes | 24,840 | 21,633 | 16,865 | 14,650 | 14,743 |
| Utility operating revenues | 327,267 | 315,248 | 284,904 | 264,206 | 264,671 |
| Non-utility operating revenues | 12,909 | 9,745 | 6,591 | 9,210 | 8,130 |
| Net operating revenues | $ 340,176 | $ 324,993 | $ 291,495 | $ 273,416 | $ 272,801 |
| Net income | $ 63,415 | $ 58,149 | $ 50,572 | $ 45,983 | $ 43,792 |
| Redeemable preferred and preference stock dividend requirements | - | - | - | 294 | 2,280 |
| Earnings applicable to common stock | $ 63,415 | $ 58,149 | $ 50,572 | $ 45,689 | $ 41,512 |
| Average common shares outstanding: | | | | | |
| Basic | 27,540 | 27,564 | 27,016 | 25,741 | 25,431 |
| Diluted | 27,657 | 27,621 | 27,283 | 26,061 | 25,814 |
| Earnings per share of common stock: | | | | | |
| Basic | $ 2.30 | $ 2.11 | $ 1.87 | $ 1.77 | $ 1.63 |
| Diluted | $ 2.29 | $ 2.11 | $ 1.86 | $ 1.76 | $ 1.62 |
| Dividends per share of common stock | $ 1.39 | $ 1.32 | $ 1.30 | $ 1.27 | $ 1.26 |
| Total assets – at end of period | $1,956,856 | $2,042,304 | $1,732,195 | $1,585,379 | $1,467,277 |
| Redeemable preferred stock | $ - | $ - | $ - | $ - | $ 8,250 |
| Long-term debt | $ 517,000 | $ 521,500 | $ 484,027 | $ 500,319 | $ 445,945 |
| Ratio of earnings to fixed charges | 3.40 | 3.32 | 3.02 | 2.84 | 2.85 |

1 Unbilled revenues have been allocated by class for 2006, 2005 and 2004.

Certain amounts from prior years have been reclassified to conform, for comparison purposes, with the current financial statement presentation. These reclassifications had no impact on prior year consolidated results of operations.

## SELECTED FINANCIAL DATA (continued)

| Thousands, except customer and gas cost per therm data | 2006 | 2005 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|
| Capitalization - at end of period | | | | | |
| Common stock equity | $ 599,545 | $ 586,931 | $ 568,517 | $ 506,316 | $ 482,392 |
| Redeemable preferred stock | - | - | - | - | 8,250 |
| Long-term debt | 517,000 | 521,500 | 484,027 | 500,319 | 445,945 |
| Total capitalization | $1,116,545 | $1,108,431 | $1,052,544 | $1,006,635 | $ 936,587 |
| Gas sales and transportation deliveries (therms): | | | | | |
| Residential | 382,665 | 371,538 | 352,356 | 343,534 | 357,091 |
| Commercial | 242,683 | 233,987 | 222,875 | 226,257 | 240,155 |
| Industrial - firm | 66,971 | 74,880 | 62,843 | 55,314 | 63,215 |
| Industrial - interruptible | 112,736 | 149,106 | 104,278 | 47,994 | 26,241 |
| Unbilled therms[1] | - | - | - | 12,099 | (6,617) |
| Total gas sales | 805,055 | 829,511 | 742,352 | 685,198 | 680,085 |
| Transportation | 387,594 | 328,056 | 389,514 | 414,554 | 445,999 |
| Total volumes delivered | 1,192,649 | 1,157,567 | 1,131,866 | 1,099,752 | 1,126,084 |
| Customers (average for period): | | | | | |
| Residential | 564,700 | 545,163 | 525,976 | 510,336 | 492,871 |
| Commercial | 59,889 | 58,914 | 57,973 | 56,504 | 55,416 |
| Industrial - firm | 650 | 666 | 629 | 362 | 350 |
| Industrial - interruptible | 197 | 201 | 178 | 98 | 74 |
| Transportation | 99 | 78 | 106 | 179 | 190 |
| Total customers | 625,535 | 605,022 | 584,862 | 567,479 | 548,901 |
| Customer statistics: | | | | | |
| Heat requirements: | | | | | |
| Actual degree days | 4,089 | 4,178 | 3,853 | 3,952 | 4,232 |
| Percent colder (warmer) than average | (4%) | (2%) | (10%) | (7%) | (1%) |
| Average annual use per customer in therms: | | | | | |
| Residential | 678 | 682 | 670 | 673 | 725 |
| Commercial | 4,052 | 3,972 | 3,844 | 4,004 | 4,334 |
| Gas purchased cost per therm - net (cents) | 75.37 | 71.42 | 56.60 | 46.99 | 51.07 |

[1] Unbilled therms have been allocated by class for 2006, 2005 and 2004.

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

The following is management's assessment of Northwest Natural Gas Company's financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated activities for the three years ended December 31, 2006. References in this discussion to "Notes" are to the Notes to Consolidated Financial Statements in this report.

The consolidated financial statements include the accounts of Northwest Natural Gas Company, which principally consists of our regulated local gas distribution business, our regulated gas storage business, and our other non-regulated businesses, which includes our wholly-owned subsidiary business, NNG Financial Corporation (Financial Corporation). In this report, the term "utility" is used to describe our regulated gas distribution business, and the term "non-utility" is used to describe our gas storage business segment (gas storage), previously referred to as "interstate gas storage," and our other non-regulated activities (other) (see Note 2).

In addition to presenting results of operations and earnings amounts in total, certain measures are expressed in cents per share. These amounts reflect factors that directly impact earnings. We believe this per share information is useful because it enables readers to better understand the impact of these factors on earnings. All references in this report to earnings per share are on the basis of diluted shares (see Note 1, "Earnings Per Share").

### Executive Summary

Our strategy in 2006 was to remain focused on profitably growing our regulated utility and gas storage businesses. The utility is our largest business segment with approximately 98 percent of consolidated total assets, which contributed 90 percent of consolidated net income in 2006. Factors critical to the success of the utility include maintaining a safe and reliable distribution system, acquiring an adequate supply of gas, providing distribution services at a competitive price, and being able to recover the operating and capital costs of the utility in the rates charged to customers. The utility is regulated by two state commissions, the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC).

Our gas storage segment represents approximately 2 percent of consolidated total assets and contributed 9 percent of consolidated net income in 2006. This business unit primarily provides firm and interruptible gas storage at our Mist underground storage facility to large interstate and intrastate customers using storage and related transportation capacity that is in excess of our utility's core (residential, commercial and industrial firm) customer requirements. Asset optimization is also part of the gas storage segment, with optimization services provided for the utility under an agreement with an independent energy marketing company. Factors critical to the success of our gas storage business segment include the ability to: develop additional storage capacity at competitive market prices; plan for the replacement of capacity that is expected to be recalled by the utility to serve its core customers in the future; and obtain timely and reasonable rate changes.

Highlights of 2006 include:

- Net income and diluted earnings per share increased 9 percent in 2006, to $63.4 million and $2.29 per share;

- Solid growth in net operating revenues from our regulated utility distribution and gas storage businesses were major drivers to increased earnings in 2006;
- Net operating revenues from our regulated utility increased 4 percent to $327.3 million, largely attributable to strong customer growth, which increased by more than 3 percent for the 20th consecutive year, and increased margin sharing from gas cost savings through our regulatory incentive mechanism;
- Net operating revenues from gas storage increased 33 percent to $12.8 million, including a higher amount of revenue sharing with our utility customers, which increased 43 percent to $7.0 million;
- Operations and maintenance expense increases were held to 1 percent in 2006, including incremental costs for employee retirement and severance programs and employee bonuses tied to improved financial results which were largely offset by cost reductions from business process redesign initiatives that we began implementing in 2006;
- Cash flow from operations increased 88 percent to $148.6 million, reflecting strong operating and working capital results;
- $25 million of new long-term debt was issued in the fourth quarter of 2006, with the proceeds being used to redeem short-term debt and fund capital expenditures;
- In a J.D. Power & Associates' residential customer survey, NW Natural ranked first in the nation for customer satisfaction with billing and payment services, and third in the nation for overall customer satisfaction among the 56 largest gas utilities; and,
- Our quarterly common stock dividend rate increased 3 percent to $0.355 per share in the fourth quarter of 2006, making this the 51st consecutive year of increasing dividends paid to shareholders.

Issues, Challenges and Performance Measures

A number of factors affect our operations and financial performance. The most significant issue the utility faces in the near term is high gas prices. Wholesale gas prices over the past few years have increased significantly, primarily due to increasing demand. In 2005, the gas supply market tightened significantly as hurricanes hit parts of the United States, resulting in the disruption of gas supplies and causing gas prices to spike. Since then, gas prices have moderated and are now relatively more stable than last year. We expect energy prices to remain slightly higher than in the past few years, with higher gas prices already reflected in our customers' bills for the 2006-07 heating season. We believe we have sufficient supplies of natural gas under contract to meet the needs of our firm customers, but further price increases for gas could change our competitive advantage and our customers' preference for natural gas. If higher gas prices persist, it could significantly affect our ability to add residential and commercial customers and could result in industrial customers shifting their businesses' energy needs to alternative fuel sources. To address these competitive issues, we are continually developing new gas acquisition strategies to manage gas prices and meet market demands, and we are working on initiatives intended to improve operational efficiencies throughout the company through a comprehensive business process redesign effort (see "Business Process Redesign," below).

Other issues and challenges we expect to face in 2007 include executing on our business process redesign initiatives, managing gas supplies and prices under unpredictable market conditions, managing the potential impact of adverse regulatory actions or policy changes, managing storage and transportation capacity, managing and maintaining customer growth, maintaining a competitive advantage over alternative fuels and managing environmental risks and exposures and higher interest rates. For a more detailed discussion of these and other risks, see "Part I, Item 1A—Risk Factors," above, “Item 7A., Quantitative and Qualitative Disclosures About Market Risk,” below, and “Forward-Looking Statements,” below, following Item 7A.

Our strategic plan addresses the risks affecting our business by focusing on:

- improving our ability to add customers profitably;
- managing wholesale natural gas prices through an active hedging program to keep customer prices stable and as low as possible;
- maintaining our reputation for exemplary customer service;
- reducing business risks;
- managing all costs, including capital investments;
- maintaining a strong financial position;
- improving our cost structure through business process redesign initiatives; and
- judiciously growing beyond our local distribution business where such growth would complement our core assets and competencies.

Return on invested capital and common equity ratios are key indicators of our operating performance and financial condition. We compare our utility return on equity results each year against the return authorized by the OPUC. We also compare our total shareholder return (stock price appreciation plus dividends) against a peer group of local gas distribution companies because it is necessary for us to attract investors so that we can continue to cost-effectively raise the capital needed to run our businesses. Other key performance measures we use in monitoring progress against our goals include earnings per share, cash provided by operations, free cash flow (cash from operations less payments for investing activities and dividends), customer satisfaction ratings, customer additions, operations and maintenance expense per customer, construction cost per meter installed and non-revenue producing capital expenditures per customer.

Strategic Opportunities

***Business Process Redesign.*** During 2006, we initiated a project to evaluate our business processes and costs against our peers and to redesign those processes where long-term efficiencies could be gained. We identified a number of areas where we could restructure our business to gain efficiencies, including more centralization, an increased focus on process orientation, and more standardized processes. In order to effectively implement these strategies, we are taking steps to redesign our business into the following six core areas to more effectively group and focus resources around our business processes:

- ***Acquire Customers.*** Focuses on the integration of activities involved in acquiring customers, including construction, sales, marketing and operation of our retail appliance center.
- ***Serve Customers.*** Focuses on all aspects of how we serve our customer base, including customer contact, meter reading, account services and field services areas.
- ***Deliver Gas.*** Focuses on the transportation of gas to our customers and includes qualification assurance of our employees, engineering and code compliance.
- ***Energy Supply.*** Focuses on procuring gas, pipeline integrity, gas storage and business development for the future.
- ***Resource Management.*** Focuses on how well we use the resources at our disposal by centralizing dispatch and scheduling, business analysis and technology implementation.
- ***Business Services.*** Focuses on supporting all of the areas above through human resources, information technology, regulation, finance, legal and other administrative functions.

We have begun the implementation of this business model, which is expected to continue over the next several years. Workforce reductions related to the implementation of this new model are expected to be accomplished primarily through attrition and voluntary severance arrangements. In 2006, we incurred costs of $1.9 million related to workforce reductions of approximately 80 employees.

***Pipeline Diversity.*** In September 2006, we announced that we are evaluating a potential pipeline project that would connect TransCanada's Gas Transmission Northwest (GTN) interstate transmission line to our local gas distribution system. We have commenced a process to determine if there is sufficient interest by potential customers to justify construction of the pipeline. If the project is determined to be viable, we would form a partnership with GTN to build and own the pipeline. In addition to owning a share of the pipeline, we would anticipate being a large user of the pipeline and GTN would be its operator. The pipeline would be intended to provide our utility customers and GTN's customers with a more diversified delivery source and greater reliability of gas supplies from the interstate system. The decision on whether to proceed with the development of the pipeline is expected to be made in 2007. No material contractual obligations related to the pipeline have been incurred as of December 31, 2006. If constructed, commercial operation would be expected to commence in 2011.

Earnings and Dividends

Net income was $63.4 million, or $2.29 a diluted share, for the year ended December 31, 2006, compared to $58.1 million, or $2.11 a share, and $50.6 million, or $1.86 a share, for the years ended December 31, 2005 and 2004, respectively. Returns on equity for these three years were 10.7 percent, 10.1 percent and 9.4 percent, respectively.

*2006 compared to 2005:*

Positive factors contributing to increased earnings were:

- increased utility volumes and net operating revenues (margin) from sales to residential and commercial customers due to 3.1 percent customer growth, plus extended coverage from the weather normalization and conservation mechanisms in Oregon, partially offset by weather that was 4 percent warmer than average and 2 percent warmer than 2005 (see "Results of Operations—Comparison of Gas Distribution Operations," below, and "Results of Operations—Regulatory Matters—Rate Mechanisms," below);
- increased margin from regulatory sharing of gas cost savings, from $4.2 million in 2005 to $8.1 million in 2006, partially offset by a $2.7 million temporary unrealized loss related to a derivative contract that will settle and reverse in 2007; and
- increased gas storage margin over the prior year, primarily due to increased storage contract volumes and increased optimization revenue from the independent energy marketing company.

Partially offsetting the above positive factors were:

- increased property tax and depreciation expenses related to increased utility plant in service, which were partially covered by revenue increases approved in the most recent Purchased Gas Adjustment (PGA) filings in Oregon and Washington;

- increased operations and maintenance expense related to higher bonuses tied to improved performance results and to employee severance charges tied to business redesign initiatives, partially offset by lower payroll and employee benefit costs; and
- increased income tax expense related to higher taxable income.

*2005 compared to 2004:*

Positive factors contributing to increased earnings were:

- increased utility volumes and net operating revenues from sales to residential and commercial customers due to 3.4 percent customer growth, 8 percent colder weather and conservation tariff mechanisms, partially offset by declining average use per customer and a decrease in the contribution from the weather normalization mechanism (see "Results of Operations—Comparison of Gas Distribution Operations," below, and "Results of Operations—Regulatory Matters—Rate Mechanisms," below);
- decreased utility volumes but increased utility margin from industrial customers, primarily reflecting a shift of several customers to higher margin service which offset the overall decline in volumes;
- increased utility margin from miscellaneous revenues; and
- increased gas storage margin primarily due to increased storage services under contract and higher optimization revenues.

Partially offsetting the above positive factors were:

- increased operations and maintenance expense related to increased payroll and employee benefit costs, increased damages to company property, industrial customer settlement charges and employee severance charges;
- increased property tax and depreciation expenses related to increased utility plant in service, which were partially covered by revenue increases approved in the most recent PGA and general rate cases in Oregon and Washington; and
- increased income tax expense related to higher taxable income.

Dividends paid on our common stock were $1.39 a share in 2006, compared to $1.32 a share in 2005 and $1.30 a share in 2004. The current indicated annual dividend rate is $1.42 per share.

Application of Critical Accounting Policies and Estimates

In preparing our financial statements using generally accepted accounting principles in the United States of America (GAAP), management exercises judgment in the selection and application of accounting principles, including making estimates and assumptions that affect reported amounts of assets, liabilities, revenues, expenses and related disclosures in the financial statements. Management considers our critical accounting policies to be those which are most important to the representation of our financial condition and results of operations and which require management's most difficult and subjective or complex judgments, including accounting estimates that could result in materially different amounts if we reported under different conditions or used different assumptions.

Our most critical estimates or judgments involve regulatory cost recovery, revenue recognition, derivative instruments, pension assumptions, income taxes and environmental contingencies.

Management has discussed the estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board. Our critical accounting policies and estimates are described below.

Within the context of our critical accounting policies and estimates, management is not currently aware of any reasonably likely events or circumstances that would result in materially different amounts being reported.

Regulatory Accounting

We are regulated by the OPUC and WUTC, which establish our utility rates and rules governing utility services provided to customers, and, to a certain extent, set forth the accounting treatment for certain regulatory transactions. In general, we use the same accounting principles as non-regulated companies reporting under GAAP. However, certain accounting principles, primarily Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," require different accounting treatment for regulated companies to show the effects of such regulation. For example, we account for the cost of gas using a PGA deferral and cost recovery mechanism, which is submitted for approval annually to the OPUC and WUTC (see "Results of Operations—Regulatory Matters—Rate Mechanisms," below). There are other expenses or revenues that the OPUC or WUTC may require us to defer for recovery or refund in future periods. SFAS No. 71 requires us to account for these types of deferred expenses (or deferred revenues) as regulatory assets (or regulatory liabilities) on the balance sheet. When we are allowed to recover these expenses from or refund them to customers, we recognize the expense or revenue on the income statement at the same time we realize the adjustment to amounts included in utility rates charged to customers.

The conditions we must satisfy to adopt the accounting policies and practices of SFAS No. 71, which are applicable to regulated companies, include:

- an independent regulator sets rates;
- the regulator sets the rates to cover specific costs of delivering service; and
- the service territory lacks competitive pressures to reduce rates below the rates set by the regulator.

We continue to apply SFAS No. 71 in accounting for our regulated utility operations. Future regulatory changes or changes in the competitive environment could require us to discontinue the application of SFAS No. 71 for some or all of our regulated businesses. This would require the write-off of those regulatory assets and liabilities that would no longer be probable of recovery from or refund to customers. Based on current regulatory and competitive conditions, we believe that it is reasonable to expect continued application of SFAS No. 71 for our regulated activities, and that all of our regulatory assets and liabilities at December 31, 2006 and 2005 are recoverable or refundable through future customer rates. See Note 1, "Industry Regulation."

Revenue Recognition

Utility revenues, derived primarily from the sale and transportation of natural gas, are recognized when gas is delivered to and received by the customer. Revenues are accrued for gas delivered to customers, but not yet billed, based on estimates of gas deliveries from the last meter reading date to month end (accrued unbilled revenues). Accrued unbilled revenues are primarily based on a percentage estimate of our unbilled gas each month, which is dependent upon a number of factors, some of which require management's judgment. These factors include total gas receipts and deliveries, customer meter reading dates, customer usage patterns and weather. Accrued unbilled revenue estimates are reversed the following month when actual billings occur. Estimated unbilled revenues at December 31, 2006 and 2005 were $87.5 million and $81.5 million, respectively. The increase in accrued unbilled revenues at year-end 2006 was primarily due to higher gas prices included in customer rates and higher volumes reflecting customer growth. If the estimated percentage of unbilled volume at December 31, 2006 was adjusted up or down by 1 percent, then our unbilled revenues, net operating revenues and net income would have increased or decreased by an estimated $3.4 million, $0.7 million and $0.4 million, respectively.

Non-utility revenues, derived primarily from our gas storage business segment, are recognized upon delivery of the service to customers. Revenues from our optimization partner are recognized over the life of the optimization contract for the guaranteed amount, or are recognized as they are earned for amounts above the guaranteed value based on information provided by the independent energy marketing company.

Accounting for Derivative Instruments and Hedging Activities

Our Financial Derivatives Policy and Gas Acquisition Policy set forth guidelines for using selected financial derivative products to support prudent risk management strategies within designated parameters. These policies specifically prohibit the use of derivatives for trading or speculative purposes. The accounting rules for determining whether a contract meets the definition of a derivative instrument or qualifies for hedge accounting treatment are complex. The contracts that qualify as derivative instruments are recorded on our balance sheet at fair value. If certain regulatory conditions are met, then the fair value is recorded together with an offsetting entry to a regulatory asset or liability account pursuant to SFAS No. 71 (see Note 1, "Industry Regulation,") and no gain or loss is recognized in current income. The gain or loss from the fair value of a derivative instrument that is subject to regulatory deferral is included in the recovery from, or refund to, utility customers in future periods (see "Regulatory Accounting," above). If a derivative contract is not subject to regulatory deferral, then the accounting treatment for gains and losses is made in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149, collectively referred to as SFAS No. 133 (see Note 1, "Derivatives" and "Industry Regulation"). Our estimate of fair value is determined from period-to-period based on an internal discounted cash flow model using exchange-based forward market prices that are subject to market volatility, except for option contracts where fair value is based on a Black-Scholes model. The estimate of fair value may change significantly from period-to-period depending on market conditions and prices. These changes may have a material impact on our results of operations, but the impact would be largely mitigated due to the majority of our derivatives activities being subject to regulatory deferral treatment. For estimated fair values at December 31, 2006 and 2005, see Note 11.

Derivative contracts entered into after our annual PGA filing for the current gas contract period are subject to a regulatory incentive sharing mechanism in Oregon, with 67 percent of unrealized gains and losses recorded to a regulatory asset or liability account and the remaining 33 percent recognized in current income. The unrealized loss on financial derivative contracts entered into during the fourth quarter of 2006, which was after the 2006 PGA filing, totaled $9.5 million, of which $2.9 million was recorded in cost of gas as of December 31, 2006. This unrealized loss will be reversed in 2007 when the derivative contracts are settled.

The following table summarizes the amount of realized gains and losses from commodity price and currency hedge transactions for the last three years:

| Thousands | 2006 | 2005 | 2004 |
| --- | --- | --- | --- |
| Net gain (loss) on commodity-price swaps—for utility | $(18,849) | $90,205 | $44,888 |
| Net loss on commodity-price options—for utility | (1,160) | (1,315) | (2,464) |
| Subtotal on commodity—for utility | (20,009) | 88,890 | 42,424 |
| Net loss on commodity-price swaps—for gas storage | - | - | (186) |
| Net gain on foreign currency forward purchases—for utility | 355 | 532 | 219 |
| Total realized net gain (loss) | $(19,654) | $89,422 | $42,457 |

Realized gains (losses) from commodity-price and foreign currency forward purchase contracts are recorded as reductions (increases) to the cost of gas and are included in the calculation of annual PGA rate changes. Unrealized gains and losses resulting from mark-to-market valuations are generally not recognized in current income or other comprehensive income, but are recorded as regulatory liabilities or regulatory assets, which are offset by a corresponding balance in non-trading derivative assets or liabilities (see Note 11).

Accounting for Pensions

We maintain two qualified non-contributory defined benefit pension plans covering all regular employees with more than one year of service, several non-qualified supplemental pension plans for eligible executive officers and certain key employees and other employee postretirement benefit plans. Only the two qualified defined benefit pension plans have plan assets, which are held in a qualified trust to fund retirement benefits.

Net periodic pension costs (pension costs) and projected benefit obligations (benefit obligations) are determined in accordance with SFAS No. 87, "Employers' Accounting for Pensions," using a number of key assumptions including discount rates, rate of compensation increases, retirement ages, mortality rates and the expected long-term return on plan assets (see "Financial Condition—Pension Cost and Funding Status," below, and Note 7). These key assumptions have a significant impact on the amounts reported. Pension costs consist of service costs, interest costs, the amortization of actuarial gains, losses and prior service costs, the expected returns on plan assets and, in part, on a market-related valuation of assets. The market-related valuation reflects differences between expected returns and actual investment returns, which are recognized over a three-year period from the year in which they occur, thereby reducing year-to-year volatility in pension costs.

Effective December 31, 2006, the funded status of our pension plans is required to be recognized in accordance with SFAS No. 158 (see "Employers' Accounting for Defined Benefit Pension and Other Postretirement Benefit Plans" under Note 1, "New Accounting Standards"). SFAS No. 158 requires balance sheet recognition of the overfunded or underfunded status of our pension plans in accumulated other comprehensive income (AOCI), net of tax, based on the fair value of plan assets compared to the actuarial value of future benefit obligations. However, the pension costs relating to certain NW Natural pension plans are recovered in utility rates based on SFAS No. 87, and as such we received regulatory approval from the OPUC to record a regulatory asset or regulatory liability, rather than include AOCI in common equity, for the funded status of those plans pursuant to SFAS No. 71 (see "Regulatory Accounting", above, and Note 1, "Industry Regulation"). As a result of regulatory approval we recognized a $54.4 million regulatory asset for the unfunded status of these qualified pension and other postretirement benefit plans. If future regulatory changes are to occur that will affect our ability to recover pension costs based on SFAS No. 87, then we would be required to adjust a portion or all of the deferred regulatory asset amount for pension and other postretirement benefit plans. This would cause us to recognize the $33.2 million after-tax charge to common equity and a $21.2 million deferred income tax asset based on the December 31, 2006 funded status, but it would not have an immediate impact on current earnings. Upon adoption of SFAS No. 158, total assets increased $25.7 million, total liabilities increased $26.1 million and equity decreased $0.4 million (see Note 7).

A number of factors are considered in developing pension assumptions, including an evaluation of relevant discount rates, expected long-term investment returns, plan asset allocations, expected changes in salaries, wages and retirement benefits, analyses of current market conditions and input from actuaries and other consultants. For the December 31, 2006 measurement date, we:

- increased the pension discount rate assumptions from 5.75 percent to a range of 6.00 percent to 6.05 percent. The new rate assumptions were determined for each plan based on a matching of the estimated cash flow, which reflects the timing and amount of future benefit payments, to the Citigroup Above Median Curve, which consists of high quality bonds (rated AA- or higher by Standard & Poor's or Aa3 or higher by Moody's Investor Service);
- updated the retirement and withdrawal rates based on a recent study of actual plan experience;
- confirmed the expected rate of future compensation increases between 4.00 and 5.00 percent; and
- confirmed the expected long-term return on plan assets at 8.25 percent.

The benefit obligation at December 31, 2006 decreased $9.3 million due to the increase in the discount rate and increased $0.3 million due to the retirement and withdrawal rates updated for actual experience.

We determine the expected long-term rate of return on plan assets by averaging the expected earnings for the target asset portfolio. In developing our expected rate of return assumption, we evaluate an analysis of historical actual performance and long-term return projections, which gives consideration to the current asset mix and our target asset allocation. The actual annualized returns for the past one-year, five-year and 10-year periods ended December 31, 2006 were 14.9 percent, 10.1 percent and 10.2 percent, respectively.

We believe our pension assumptions to be appropriate based on plan design and an assessment of market conditions. However, the following shows the sensitivity of our pension costs and benefit obligations to future changes in certain actuarial assumptions:

| Thousands, except percent | Change in Assumption | Impact on 2006 Pension Costs | Impact on Benefit Obligations at Dec. 31, 2006 |
|---|---|---|---|
| Discount rate | (0.25%) | $884 | $8,506 |
| Expected long-term return on plan assets | (0.25%) | $534 | N/A |

The impact of a change in pension costs on operating results would be less than the amounts shown above because only between 60 and 70 percent of our pension costs is charged to operations and maintenance expense. The remaining 30 to 40 percent is capitalized to construction accounts as payroll overhead and included in utility plant, which is amortized to expense over the useful life of the asset placed into service.

Accounting for Income Taxes

Income taxes are accounted for in accordance with SFAS No. 109, "Accounting for Income Taxes," by recognizing deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities at current income tax rates.

SFAS No. 109 also requires the recognition of additional deferred income tax assets and liabilities for temporary differences where regulators require us to flow through deferred income tax benefits or expenses in the ratemaking process of the regulated utility (regulatory tax assets and liabilities). This is consistent with the ratemaking policies of the OPUC and WUTC. Regulatory tax assets and liabilities are recorded to the extent we believe they will be recoverable from, or refunded to, customers in future rates. At December 31, 2006 and 2005, we had regulatory assets representing differences between book and tax basis related to pre-1981 property of $67.1 million and $65.8 million, respectively, and recorded an offsetting deferred tax liability for the same amounts (see Note 1, "Income Tax Expense"). We believe that it is reasonable to expect recovery of these regulatory assets through future customer rates. However, future regulatory changes could require the write-off of all or a portion of these regulatory assets should they no longer be probable of recovery in future rates (see "Regulatory Accounting," above, and Notes 1 and 9).

A recent interpretation of SFAS No. 109 (FIN 48), "Accounting for Uncertainty in Income Taxes – an interpretation of Financial Accounting Standards Board (FASB) Statement No. 109," was issued by the FASB in July 2006 to address how companies should account for the tax benefits of timing and permanent income tax positions taken or expected to be taken in a tax return. SFAS No. 109 contains rules which set out how the benefits of tax positions taken or expected to be taken in a tax return are to be reflected in current and deferred income taxes for financial reporting purposes, but it does not establish a confidence level or threshold that must be met in order to recognize a tax benefit in the financial statements. FIN 48 is effective for fiscal years beginning after December 15, 2006, which for us was January 1, 2007.

Adoption of FIN 48 will require us to identify and evaluate all material tax positions taken in previously filed and still open tax returns as well as tax positions expected to be taken in future returns. Each tax position will need to be examined to determine whether the more likely than not recognition standard has been met, and if so, to compute the amount of the tax benefit to be recognized under FIN 48. Based upon a preliminary assessment of the application of FIN 48, the adoption of FIN 48 is not expected to have a material effect on our financial condition, results of operations or cash flows.

Contingencies

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with SFAS No. 5, "Accounting for Contingencies." Estimates of loss contingencies, including estimates of legal defense costs when such costs are probable of being incurred and are reasonably estimable, and related disclosures are updated when new information becomes available. Estimating probable losses requires an analysis of uncertainties that often depend upon judgments about potential actions by third parties. Accruals for loss contingencies are recorded based on an analysis of potential results, developed in consultation with outside counsel and consultants when appropriate. When information is sufficient to estimate only a range of potential liabilities, and no point within the range is more likely than any other, we recognize an accrued liability at the low end of the range and disclose the range (see "Contingent Liabilities," below). It is possible, however, that the range of potential liabilities could be significantly different than amounts currently accrued and disclosed, with the result that our financial condition and results of operations could be materially affected by changes in the assumptions or estimates related to these contingencies.

With respect to our environmental liabilities and related costs, we develop estimates based on currently available information, existing technology and environmental regulations. We previously received regulatory approval to defer and seek recovery of costs related to certain sites and believe the recovery of any costs not recovered under our general liability insurance policies is probable through the regulatory process (see Note 12). In accordance with SFAS No. 71, we recorded a regulatory asset for the amount expected to be recovered. We intend to first pursue recovery for these environmental costs from our general liability insurance policies, which, to the extent successful, would require a corresponding reduction in the regulatory asset. At December 31, 2006, $27.8 million in environmental costs have been recorded as a regulatory asset, including $19.1 million of costs paid to-date and $8.7 million accrued for estimated future environmental costs. If it is determined that both the insurance recovery and future rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made and could have a material impact on our financial condition or results of operations.

## Results of Operations

### Regulatory Matters

#### Regulation and Rates

We are subject to regulation with respect to, among other matters, rates, systems of accounts and issuance of securities by the OPUC and the WUTC. In 2006, 93 percent of our utility gas deliveries and 90 percent of our utility operating revenues were derived from Oregon customers and the balance from Washington customers. Future earnings and cash flows from utility operations will be determined largely by the pace of continued growth in the residential and commercial markets and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery for our utility gas costs, operating and maintenance costs and investments made in utility plant.

#### General Rate Cases

Our most recent general rate increase in Oregon authorized rates to customers based on a return on shareholders' equity (ROE) of 10.2 percent and was effective September 1, 2003. Our most recent general rate case in Washington authorized a revenue increase of $3.5 million per year but did not specifically authorize an ROE and was effective July 1, 2004.

In May 2005, we reached a settlement with the staff of the Federal Energy Regulatory Commission (FERC) and all intervenors with respect to our rate case filed in January 2005 related to Mist interstate storage service. The settlement provided for a small net increase in the maximum rates for our interstate storage services, which became effective July 1, 2005. The rates established in this case are designed to reflect updated costs related to investments in the Mist gas storage facility since 2001 and costs associated with the South Mist Pipeline Extension project.

#### Rate Mechanisms

***Purchased Gas Adjustment***. Rate changes are applied each year under the PGA tariff mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including contractual arrangements to hedge the purchase price with financial derivatives (see "Comparison of Gas Distribution Operations—Cost of Gas Sold," below), interstate pipeline demand charges, the application of temporary rate adjustments to amortize balances in deferred regulatory accounts and the removal of temporary rate adjustments effective for the previous year. Under the current PGA mechanisms, we collect an amount for purchased gas costs based on estimates included in rates. If the actual purchased gas costs differ from the estimated amounts included in rates, then we are required to defer that difference and pass it on to customers as an adjustment to future rates. As part of an incentive mechanism in Oregon, only 67 percent of the difference is deferred such that the impact on current earnings is either a charge to expense for 33 percent of the higher cost of gas sold, or a credit to expense for 33 percent of the lower cost of gas sold. In Washington, the PGA deferral is 100 percent of the higher or lower actual cost of gas sold.

The OPUC and the WUTC approved PGA rate increases on October 25, 2006 that became effective on November 1, 2006. The effect of the PGA rate changes was to increase the average monthly bills of Oregon residential sales customers by 3.5 percent and those of Washington residential sales customers by 2.6 percent. The OPUC also approved a modification to our PGA deferral mechanism, effective November 1, 2006, which provides that we use actual recoveries of gas costs in revenues billed (instead of the prior method that used estimated deliveries for gas costs incorporated in monthly rates) compared to actual purchased gas costs. The new method requires changes in line loss expense to be subject to the PGA deferral mechanism, with 67 percent of any cost differences for Oregon volumes deferred for refund or recovery in customer rates in subsequent periods and the remaining 33 percent included in current earnings. These PGA increases included increased transportation costs (see "Interstate Pipeline Rate Cases," below).

Pursuant to the PGA tariffs, rate increases were approved by the OPUC averaging 15.2 percent for Oregon residential sales customers, and by the WUTC averaging 12.0 percent for Washington residential sales customers, both effective October 1, 2005. In 2004, the OPUC approved a PGA rate increase averaging 20.1 percent for Oregon residential sales customers, and the WUTC approved a PGA rate increase averaging 19.5 percent for Washington residential sales customers, effective October 1 and November 1, 2004, respectively.

The OPUC notified us that they will be conducting a formal review of the PGA process covering gas portfolio requirements, incentive sharing levels and filing requirements, among other items. The investigation is expected to be completed in early 2008. Implementation of any changes to the PGA mechanism is expected to be effective with the 2008 PGA filing.

***Conservation Tariff***. In October 2002, the OPUC authorized the implementation of a "conservation tariff," which is a rate mechanism designed to adjust margin to compensate the utility for changes in consumption patterns due to residential and commercial customers' conservation efforts. The tariff is a decoupling mechanism that is intended to break the link between earnings and the quantity of energy consumed by customers, removing any incentive to discourage customers' conservation efforts. In Washington, customer use is not covered by a conservation tariff, and as such our utility earnings are affected by increases and decreases in usage based on customers' conservation efforts. Washington customers account for about 10 percent of utility revenues.

In 2005, an independent study to measure the mechanism's effectiveness recommended continuation of the conservation tariff, with minor modifications. In 2005 and 2006, the OPUC approved the continuations of the conservation tariff through September 30, 2009, and increased the mechanism's coverage from a partial decoupling of 90 percent of residential and commercial gas usage to a full decoupling of 100 percent.

***Weather Normalization***. In November 2003, the OPUC authorized, and the utility implemented, a weather normalization mechanism in Oregon that helps stabilize utility margins by adjusting residential and commercial customer billings based on temperature variances from average weather. The current normalization mechanism is applied to our residential and commercial customers' bills between December 1 and May 15 for each heating season. The mechanism adjusts the margin component of customers' rates to reflect average weather, which uses the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers (see "Comparison of Gas Distribution Operations," below). We do not have a weather normalization mechanism approved for our Washington customers.

***Excess Earnings Test.*** The OPUC has a formalized process to test for excess utility earnings annually and has confirmed our ability to pass through 100 percent of prudently incurred gas costs into rates. We are authorized to retain all of our earnings up to a threshold level equal to our authorized ROE of 10.2 percent plus 300 basis points. One-third of any earnings above that level will be refunded to customers. The excess earnings threshold is subject to adjustment up or down each year depending on movements in long-term interest rates. In 2006 and 2005, the threshold after adjustment was 13.44 percent and 13.32 percent, respectively. No amounts were required to be refunded to customers as a result of the 2005 or 2004 earnings test and we do not expect that any amounts will be required to be refunded to customers as a result of the 2006 earnings test, which will be reviewed by the OPUC during the second quarter of 2007. In Washington, we are not subject to an annual excess earnings test, and 100 percent of all prudently incurred gas costs are passed through into customer rates.

***Recent Changes to Industrial Tariffs.*** In August 2006, the OPUC and WUTC approved tariff changes to the service options for our major industrial accounts. The changes set out additional parameters that give us more certainty in the level of gas supplies we will need to acquire to serve this customer group. The parameters include an annual election period, special pricing provisions for out-of-cycle changes and a requirement that customers on our annual weighted average cost of gas tariff complete the term of their service election.

***Pipeline Integrity Cost Recovery***. In July 2004, the OPUC approved our applications relating to the accounting treatment and full recovery for the cost of the pipeline integrity management program, as mandated by the Pipeline Safety Improvement Act of 2002 and related rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (see "Financial Condition—Cash Flows—Investing Activities," below). We classify our costs as either capital expenditures or regulatory assets, accumulate the costs over each 12-month period ending June 30, and recover the costs, subject to audit, through rate changes effective with the annual PGA. The accounting and rate treatment for these costs extends through September 30, 2008 and may be reviewed for potential extension after that date. We do not have any special accounting or rate treatment for pipeline integrity costs incurred in the state of Washington.

Interstate Pipeline Rate Cases

On June 30, 2006, the two interstate pipeline companies that provide natural gas transportation to our distribution system filed for general rate increases with the FERC. Northwest Pipeline

Corporation (Northwest Pipeline) filed for an overall cost of service increase of approximately $119.0 million (a 41 percent increase), including an increase in the firm transportation rate of approximately 45 percent. In connection with this filing, our firm gas transportation rates increased by approximately $17.8 million annually. The major components in the Northwest Pipeline increase relate to a significant capacity replacement project, other capacity displacement projects, an increase in the rate of return and higher operation and maintenance expenses and costs associated with accounting changes to expense pipeline integrity assessment costs. The filed rates and associated tariff sheets became effective on January 1, 2007, subject to refund pending the outcome of further proceedings in the case. In February 2007, Northwest Pipeline filed a settlement proposal with the FERC that would resolve all issues with the active parties and would result in an increase in our transportation rates of about $12.0 million. Amounts collected from our customers in excess of this settlement amount will be deferred and returned to customers in our next PGA rate request in late 2007.

Gas Transmission Northwest's (GTN) rate case proposes, among other things, an increase in firm transportation rates of approximately 71 percent. In connection with this filing, our transportation rates on that pipeline increased by approximately $3.1 million annually. The primary reason for GTN's filing was unsubscribed capacity on the system due to significant capacity turnback and shipper defaults. The filed rates and associated tariff sheets became effective on January 1, 2007, subject to refund pending further proceedings in the case.

Increases in interstate pipeline transportation expenses are subject to our PGA mechanism and are 100 percent passed-through to customers in both Oregon and Washington. Both of the filed general rate increases were reflected in our 2006 PGA filings.

Utility Regulation Legislation

During 2005, the Oregon legislature passed Senate Bill 408 (SB 408) relating to taxes collected by utilities in rates on or after January 1, 2006. SB 408 requires Oregon investor-owned electric and gas utilities to file annual reports and other information with the OPUC. The report is to be filed by October 15 of the year following the reporting year and must identify the amount of income taxes paid, either by the utility or its consolidated group and properly attributed to the utility, as well as the amount of taxes authorized to be collected in rates. If the OPUC determines that the difference between the two amounts is greater than $100,000, the utility is required to establish an "automatic adjustment clause" to adjust rates.

In September 2006, the OPUC issued a final order adopting permanent rules to implement SB 408. The permanent rules established reference points for determining margins and effective tax rates from a utility's ratemaking proceedings. In addition, the OPUC adopted an apportionment methodology for determining taxes properly attributed to the utility from a consolidated tax filing. The OPUC also determined that interest should accrue beginning January 1, 2006, using a mid-year convention for amounts determined under the automatic adjustment clause.

Utilities subject to SB 408 were required to seek a Private Letter Ruling (PLR) from the Internal Revenue Service requesting a ruling as to whether a utility's compliance with the provisions of SB 408 would cause the utility to fail to comply with provisions of federal tax law, including the normalization requirements of the Internal Revenue Code. We submitted our PLR to the Internal Revenue Service in December 2006. While a utility's request for a PLR is pending, no rate adjustment will be implemented. However, interest will begin to accrue on the amount of any rate adjustment determined by the OPUC.

Based on our assessment of the permanent rules, we have estimated that our 2007 Tax Report for the 2006 tax year will reflect a surcharge of approximately $1.6 million; that is, the amount of taxes paid to government entities will exceed the amount of taxes the utility collected in rates, thus creating a rate adjustment that requires a reimbursement from customers. It is anticipated that any amounts due from customers for the 2006 tax year would not be realized until after June 1, 2008, pending a review by the OPUC. We have determined that the recognition of this regulatory gain in our statement of operations is uncertain until: the OPUC completes its review of how the final rules will be applied to our 2006 financial results; the underlying estimates are finalized; and efforts in the current Oregon legislative session to potentially change certain provisions of SB 408 are completed. Based on our current corporate structure and level of non-utility investments and activities, we do not expect that ongoing compliance with SB 408 will have a material adverse effect on our financial condition, results of operations or cash flows.

Comparison of Gas Distribution Operations

The following table summarizes the composition of gas utility volumes and revenues for the years ended December 31, 2006, 2005 and 2004:

| Thousands, except degree day and customer data | 2006 | 2005 | 2004 | Favorable/(Unfavorable) 2006 vs. 2005 | Favorable/(Unfavorable) 2005 vs. 2004 |
|---|---|---|---|---|---|
| Utility volumes - therms: | | | | | |
| Residential sales | 382,665 | 371,538 | 352,356 | 11,127 | 19,182 |
| Commercial sales | 242,683 | 233,987 | 222,875 | 8,696 | 11,112 |
| Industrial - firm sales | 66,971 | 74,880 | 62,843 | (7,909) | 12,037 |
| Industrial - firm transportation | 150,153 | 135,807 | 176,978 | 14,346 | (41,171) |
| Industrial - interruptible sales | 112,736 | 149,106 | 104,278 | (36,370) | 44,828 |
| Industrial - interruptible transportation | 237,441 | 192,249 | 212,536 | 45,192 | (20,287) |
| Total utility volumes sold and delivered | 1,192,649 | 1,157,567 | 1,131,866 | 35,082 | 25,701 |
| Utility operating revenues - dollars: | | | | | |
| Residential sales | $ 536,468 | $ 471,502 | $ 383,067 | $ 64,966 | $ 88,435 |
| Commercial sales | 290,666 | 250,287 | 200,424 | 40,379 | 49,863 |
| Industrial - firm sales | 66,986 | 64,507 | 45,259 | 2,479 | 19,248 |
| Industrial - firm transportation | 4,901 | 4,087 | 5,035 | 814 | (948) |
| Industrial - interruptible sales | 93,107 | 100,740 | 55,380 | (7,633) | 45,360 |
| Industrial - interruptible transportation | 7,899 | 6,668 | 7,620 | 1,231 | (952) |
| Other revenues | 161 | 2,862 | 4,160 | (2,701) | (1,298) |
| Total utility operating revenues | 1,000,188 | 900,653 | 700,945 | 99,535 | 199,708 |
| Cost of gas sold | 648,081 | 563,772 | 399,176 | (84,309) | (164,596) |
| Revenue taxes | 24,840 | 21,633 | 16,865 | (3,207) | (4,768) |
| Utility net operating revenues (margin) | $ 327,267 | $ 315,248 | $ 284,904 | $ 12,019 | $ 30,344 |
| Utility margin: (1) | | | | | |
| Residential sales | $ 204,951 | $ 195,098 | $ 172,209 | $ 9,853 | $ 22,889 |
| Commercial sales | 83,334 | 78,919 | 70,565 | 4,415 | 8,354 |
| Industrial - sales and transportation | 32,383 | 31,632 | 31,026 | 751 | 606 |
| Miscellaneous revenues | 4,333 | 4,990 | 3,472 | (657) | 1,518 |
| Other margin adjustments | 2,610 | 2,950 | (1,939) | (340) | 4,889 |
| Margin before regulatory adjustments | 327,611 | 313,589 | 275,333 | 14,022 | 38,256 |
| Weather normalization mechanism | 2,282 | (1,308) | 7,873 | 3,590 | (9,181) |
| Decoupling mechanism | (2,626) | 2,967 | 1,698 | (5,593) | 1,269 |
| Utility margin | $ 327,267 | $ 315,248 | $ 284,904 | $ 12,019 | $ 30,344 |
| Customers - end of period: | | | | | |
| Residential customers | 575,116 | 556,667 | 537,152 | 18,449 | 19,515 |
| Commercial customers | 60,523 | 59,543 | 58,548 | 980 | 995 |
| Industrial customers | 945 | 953 | 935 | (8) | 18 |
| Total number of customers - end of period | 636,584 | 617,163 | 596,635 | 19,421 | 20,528 |
| Actual degree days | 4,089 | 4,178 | 3,853 | | |
| Percent colder (warmer) than average (2) | (4%) | (2%) | (10%) | | |

(1) Amounts reported as margin for each category of customers is net of demand charges and revenue taxes.
(2) Average weather represents the 25-year average degree days, as determined in our last Oregon general rate case.

Certain amounts in prior years have been reclassified to conform to the current year presentation. These reclassifications had no impact on prior year results of operations.

*2006 compared to 2005:*

Total utility margin increased $12.0 million or 4 percent in 2006 compared to 2005 with residential and commercial customers contributing an additional $12.3 million to margin in 2006, including weather normalization and decoupling mechanisms. The $0.8 million increase in margin from industrial customers in 2006 was offset by a decrease in revenue adjustments from regulatory deferrals and amortizations and miscellaneous fees. The weather normalization and decoupling mechanisms decreased margin by a net $2.0 million in 2006 compared to 2005, primarily reflecting lower than expected consumption decline due to customer conservation efforts.

Our customer base continued to grow in 2006, with a net increase of 19,421 customers. The growth rate for 2006 was 3.1 percent, compared to 3.4 percent in 2005. The slower growth rate in 2006 was primarily due to a smaller increase in residential customers reflecting a modest slowdown in new construction.

Our utility margin results are affected by customer growth and to a certain extent by changes in weather and customer consumption patterns, with a significant portion of our earnings being derived from natural gas sales to residential and commercial customers. In Oregon, we have a conservation tariff that adjusts margin up or down based on changes in residential and commercial customer consumption, and we have a weather normalization mechanism that adjusts customer bills and our margin up or down based on above- or below-average temperatures during the winter heating season (see "Results of Operations—Regulatory Developments—Rate Mechanisms," above). Both mechanisms are designed to reduce the volatility of our utility earnings.

In 2006, weather was 2 percent warmer than in 2005. The weather normalization mechanism added $2.3 million to margin for the year ended December 31, 2006 based on weather that was 4 percent warmer than average. The mechanism reduced margin by $1.3 million in 2005 based on weather that was 2 percent warmer than average. Generally, we would have expected the weather normalization mechanism in 2005 to recover lost margin when temperatures were warmer than average, but that year we lost heating volumes and corresponding margin revenues in the latter part of May when temperatures were significantly warmer than average because those volume and margin losses were not entirely covered by the weather normalization mechanism, which ends on May 15 each year.

The decoupling mechanism decreased margin by $2.6 million in 2006, after adjusting for price elasticity in the annual Oregon PGA filing, compared to a contribution of $3.0 million in 2005.

*2005 compared to 2004:*

Total margin increased $30.3 million or 11 percent in 2005 compared to 2004 with residential and commercial customers contributing an additional $23.3 million to margin, including weather normalization and decoupling mechanisms. Industrial customers contributed an additional $0.6 million to margin, and revenue adjustments for regulatory deferrals and amortizations and miscellaneous fees increased margin by $6.4 million. The weather normalization and decoupling mechanisms adjusted margin down by $7.9 million in 2005 compared to 2004, primarily reflecting the impact of 8 percent colder weather in 2005.

Our customer base increased by 20,528 in 2005 for a growth rate of 3.4 percent, compared to 3.2 percent in 2004.

In 2005, weather was 8 percent colder than in 2004, which partially contributed to the 9 percent increase in margin from residential and commercial sales from those customers not covered by weather normalization. The weather normalization mechanism reduced margin by $1.3 million for the year ended December 31, 2005 based on weather that was 2 percent warmer than average but contributed $7.9 million to margin in 2004 based on weather that was 10 percent warmer than average.

The decoupling mechanism contributed $3.0 million to margin in 2005, after adjusting margin for expected price elasticity in the annual Oregon PGA filing, compared to a contribution of $1.7 million in 2004.

Residential and Commercial Sales

The primary factors that impact results of operations in the residential and commercial markets are seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service territory.

*2006 compared to 2005:*

- volumes sold were 3 percent higher, primarily reflecting 3.1 percent customer growth in the residential and commercial sector and improved economic conditions, partially offset by 2 percent warmer weather;
- operating revenues were 15 percent higher, primarily due to a 3 percent increase in volumes and an 11 percent increase in the average rate per therm due to recent PGA rate increases, effective October 1, 2005 and November 1, 2006; and
- margin was 5 percent higher, reflecting customer growth and higher gas cost savings from our PGA incentive sharing mechanism in Oregon (see “Cost of Gas,” below).

*2005 compared to 2004:*

- volumes sold were 5 percent higher, including unbilled sales, reflecting the impact of 3.4 percent customer growth and 8 percent colder weather partially offset by declining average consumption due to customer conservation;
- operating revenues were 24 percent higher, primarily due to a 5 percent increase in volumes and an 18 percent increase in the average rate per therm due to the PGA rate increases, effective October 1, 2004 and 2005; and,
- margin was 13 percent higher reflecting customer growth and increases in gas cost savings from our PGA incentive sharing mechanism in Oregon (see “Cost of Gas,” below).

Typically, 80 percent or more of annual utility operating revenues are derived from gas sales to weather-sensitive residential and commercial customers. Although variations in temperatures between periods will affect volumes of gas sold to these customers, the effect on margin and net income is significantly reduced with the weather normalization mechanism in Oregon (see “Regulatory Matters—Rate Mechanisms,” above). Beginning in 2006, this mechanism is effective from December 1 through May 15 of each heating season. Approximately 10 percent of our residential and commercial customers are in Washington, where the mechanism is not in effect, and about 9 percent of our eligible Oregon customers have voluntarily elected not to be covered by the mechanism, so the mechanism does not fully insulate us from earnings volatility due to weather. The mechanism increased margin by a net $2.3 million in the twelve-month period ended December 31, 2006, decreased margin by $1.3 million in 2005 and increased margin by $7.9 million in 2004.

Industrial Sales and Transportation

The primary factors that impact results of operations in the industrial sales and transportation markets are commodity costs, competitive factors in the energy industry and economic conditions in our service territory.

*2006 compared to 2005:*

- volumes delivered to industrial customers increased 15.3 million therms, or 2.8 percent, with the increase primarily in lower margin interruptible schedules;
- operating revenue decreased $3.1 million, or 1.8 percent, due to customers transferring from sales service to transportation service where cost of gas is not a component in operating revenues; and
- margin increased 2 percent, reflecting increased volumes.

*2005 compared to 2004:*

- volumes delivered to industrial customers decreased 4.6 million therms, or less than 1.0 percent;
- operating revenue increased $62.7 million, or 55 percent, reflecting a 34 percent increase in sales volumes due to customers that migrated from transportation to sales service where the cost of gas component is included in revenues and to rate increases effective October 1, 2004 and 2005; and
- margin increased 2 percent due to the migration of customers to higher margin rate schedules, partially offset by lower volumes.

Several large industrial customers transferred from sales service back to transportation service in 2006. In 2005, high natural gas prices resulted in a number of our large industrial customers switching from transportation service, where they arrange for their own supplies through independent third parties, to sales service where we sell them the gas commodity under regulatory tariffs. Our tariff requires us to charge the incremental cost of gas supply incurred to serve those customers.

Other Revenues

Other revenues include miscellaneous fee income as well as revenue adjustments reflecting deferrals to, or amortizations from, regulatory asset or liability accounts other than deferrals relating to gas costs. Other revenues increased net operating revenues by $0.2 million in 2006, compared to $2.9 million in 2005 and $4.2 million in 2004.

*2006 compared to 2005:*

Other revenues in 2006 were $2.7 million lower than in 2005 primarily due a $5.6 million decrease in deferrals under the decoupling mechanism (see "Regulatory Matters—Rate Mechanisms," above) and a $1.5 million increase in amortization of the decoupling deferrals from prior periods, partially offset by an increase of $1.3 million in interstate gas storage credits to customers reflecting increased net income from storage operations, a decrease of $1.7 million in amortization expense for the South Mist Pipeline Extension and a decrease of $1.0 million in the deferral for the Oregon income tax kicker refund.

*2005 compared to 2004:*

In 2005, other revenues were $1.3 million lower than in 2004 primarily due to a $2.6 million decrease in interstate gas storage credits to customers resulting from lower net income from storage operations and the deferral of $1.0 million for the Oregon income tax kicker refund, partially offset by a $1.1 million increase in customer late payment fees and a special enhanced service contract and a $1.3 million increase in deferrals under the decoupling mechanism (see "Regulatory Matters—Rate Mechanisms," above).

Cost of Gas Sold

Natural gas commodity prices have risen significantly in recent years. The effects of higher commodity prices and price volatility on core utility customers are mitigated, in part, through our use of underground storage facilities, fixed-price commodity hedge contracts and short term sales of excess gas supply and transportation capacity to off-system customers in periods when core utility customers do not require the full amount of contract gas supplies or firm pipeline capacity.

The total cost of gas sold was $648.1 million in 2006, an increase of $84.3 million or 15 percent compared to 2005, and cost of gas sold in 2005 was $563.8 million, an increase of $164.6 million or 41 percent higher than 2004. The cost per therm of gas sold includes current gas purchases, gas drawn from storage inventory, gains or losses from commodity hedges, margin from off-system gas sales, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use.

Under the PGA tariff in Oregon, our net income is affected within defined limits by changes in purchased gas costs (see "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above). In each of the last three years, our actual gas costs were lower than the gas costs embedded in rates, with the effect that our share of the cost savings increased margin by $8.1 million, $4.2 million and $0.6 million for 2006, 2005 and 2004, respectively.

We use a natural gas commodity-price hedge program under the terms of our Financial Derivatives Policy to help manage our exposure to floating price gas purchase contracts (see "Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities," above, and Note 11). We realized net losses of $20.0 million from our financial hedges in 2006, compared to gains of $88.9 million and $42.4 million in 2005 and 2004, respectively. Gains and losses from the financial hedging of utility gas purchases generally are included in cost of gas, which are factored into our PGA deferrals and annual rate changes, but to the extent that any utility gas hedge is entered into after the annual PGA filing, then the gains and losses are subject to our PGA incentive sharing mechanism with 67 percent deferred and 33 percent recorded to current income.

Business Segments Other than Local Gas Distribution

Gas Storage

We earned $6.0 million in net income from our non-utility gas storage business segment in 2006, after regulatory sharing and income taxes, equivalent to 21 cents a share, compared to $4.6 million or 17 cents a share in 2005 and $2.9 million or 11 cents a share in 2004 (see Note 2). Earnings from this business segment were higher in 2006 primarily because of increased net revenues from interstate storage service contracts and our contract with an independent energy marketing company that optimizes the value of our utility assets.

In Oregon, we retain 80 percent of the pre-tax income from gas storage as well as from third party optimization revenues when the costs of the capacity used have not been included in utility rates, or 33 percent of the pre-tax income from such storage and optimization when the capacity costs have been included in utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for crediting to our core utility customers. We have a similar sharing mechanism in Washington for pre-tax income derived from storage services and third party optimization.

Other

Net income from our other non-regulated investment activities was $0.8 million in both 2006 and 2005 and $0.6 million in 2004. In 2006, we recognized net income of $0.2 million from Financial Corporation, and we completed the sale of a non-utility real estate investment that contributed a $0.3 million gain, before tax. Also in 2006, we recognized an additional $0.2 million from a real estate transaction where the property was sold on an installment basis, and we reclassified our investment in a Boeing 737-300 aircraft to current assets due to the lease term expiration in 2007 and our expectation that the asset will be sold prior to year end.

Subsidiaries

Financial Corporation

Operating results in 2006 were net income of $0.2 million, compared to $0.3 million in 2005 and $0.2 million in 2004. Our investment in Financial Corporation was $2.6 million at December 31, 2006, compared to $3.1 million at December 31, 2005.

Operating Expenses

Operations and Maintenance

Operations and maintenance expenses increased by $1.3 million in 2006, or 1 percent, compared to 2005 and increased $11.1 million, or 11 percent, in 2005 compared to 2004. The following summarizes the major factors that contributed to changes in operations and maintenance expense:

*2006 compared to 2005:*

- a $2.0 million increase in payroll expense, primarily due to bonuses related to improved results on annual performance goals and an increase in the long-term incentive plan liability due to a higher total shareholder return than our peer group average on which the award is based;
- a $1.1 million increase in severance expenses related to the 2006 severance incentive plan; and
- a $0.8 million increase in stock option expense due to the required adoption of SFAS No. 123R related to stock-based compensation expense (see Note 4).

Partially offsetting the above increases were:

- a $1.2 million decrease in system damages and damage claims written-off; and
- a $2.3 million reduction in charges related to a settlement with a group of industrial customers in 2005.

*2005 compared to 2004:*

- a $3.0 million increase in regular payroll-related expense resulting from employee additions, pay increases and higher benefit costs;
- a $2.3 million increase in bonus payroll expense related to improved results on performance goals and an increase in the accrued long-term incentive plan liability due to a higher stock price on which the award is based;
- a $2.0 million charge related to a settlement with a group of industrial customers;
- a $1.0 million increase in system damages and damage claims written-off;
- a $0.9 million increase related to employee severance charges;
- a $0.4 million increase in costs for software maintenance; and
- a $0.4 million increase in costs for consumer safety advertising.

Partially offsetting the above increases was:

- a $0.3 million decrease in uncollectible accounts expense reflecting improved collection results and cash recoveries of accounts previously written-off.

Some of the cost increases we experienced in 2005 over 2004 were included in the rates approved in our general rate cases in Oregon and Washington (see "Regulatory Matters—General Rate Cases," above).

General Taxes

General taxes, which are principally comprised of property and payroll taxes, increased $1.2 million, or 5 percent, in 2006 compared to 2005, and increased $1.2 million, or 6 percent, in 2005 compared to 2004.

Payroll taxes decreased $0.1 million in 2006 compared to 2005 and decreased $0.5 million in 2005 compared to 2004. In 2004, payroll taxes included an accrual for taxes on the 2004 bonuses paid in 2005.

Property taxes increased $0.7 million in 2006 and $1.5 million in 2005 primarily due to increased utility plant in service.

Regulatory fees increased by $0.5 million or 28 percent in 2006 compared to 2005 due to higher utility operating revenues. Increases in regulatory fees are generally recovered on a timely basis through an increase in customer rates through the annual PGA filing.

Depreciation and Amortization

The following table summarizes the increases in total plant and property and total depreciation and amortization for the three years ended December 31:

| Thousands | 2006 | 2005 | 2004 |
|---|---|---|---|
| Plant and property: | | | |
| Utility plant: | | | |
| Depreciable | $1,925,837 | $1,839,206 | $1,768,630 |
| Non-depreciable, including construction work in progress | 37,661 | 36,238 | 26,342 |
| | 1,963,498 | 1,875,444 | 1,794,972 |
| Non-utility property: | | | |
| Depreciable | 36,952 | 36,920 | 27,109 |
| Non-depreciable, including construction work in progress | 5,700 | 3,916 | 6,854 |
| | 42,652 | 40,836 | 33,963 |
| Total plant and property | $2,006,150 | $1,916,280 | $1,828,935 |
| Depreciation and amortization: | | | |
| Utility plant | $ 63,552 | $ 60,935 | $ 56,899 |
| Non-utility property | 883 | 710 | 472 |
| Total depreciation and amortization expense | $ 64,435 | $ 61,645 | $ 57,371 |
| Average depreciation rate - utility | 3.4% | 3.4% | 3.4% |
| Average depreciation rate - non-utility | 2.5% | 2.6% | 2.3% |

Total depreciation and amortization expense increased by $2.8 million, or 5 percent, in 2006 and by $4.3 million, or 7 percent, in 2005. The increased expense for both years is primarily due to additional investments in utility plant to meet continuing customer growth and to make system improvements (see “Financial Condition—Cash Flows—Investing Activities,” below, and Note 9). We recently completed a depreciation study on all company plant and property, which generally indicates that depreciation rates overall would be reduced if we maintain the existing average service life depreciation method. However, if the OPUC were to adopt a different depreciation method such as the equal life group method, then depreciation rates could increase. Utility depreciation rates and methods are subject to review and approval by the OPUC and WUTC, and new rates will not be placed into service until depreciation rate proceedings are approved. We intend to submit the depreciation study for regulatory approval in 2007 and implement the new rates upon approval. We do not anticipate that adoption of these new rates will have a material impact on our financial condition or results of operations.

Other Income and Expense—Net

The following table provides details on other income and expense – net for the last three years:

| Thousands | 2006 | 2005 | 2004 |
|---|---|---|---|
| Gains from company-owned life insurance | $2,609 | $ 1,856 | $ 2,855 |
| Allowance for funds used during construction - equity | - | - | 708 |
| Interest income | 363 | 403 | 232 |
| Other non-operating expenses | (852) | (1,393) | (1,222) |
| Net interest on deferred regulatory accounts | (177) | 282 | 74 |
| Earnings from equity investments of Financial Corporation | 191 | 57 | 181 |
| Total other income | $2,134 | $ 1,205 | $ 2,828 |

Other income and expense–net improved by $0.9 million in 2006 over 2005. The increase was primarily due to higher gains of $0.8 million from company-owned life insurance, reflecting higher policy benefits realized during 2006, and a net decrease of $0.5 million in other non-operating expenses, reflecting cost reduction initiatives. These positive changes were partially offset by a $0.5 million increase in net interest charges on deferred regulatory accounts, reflecting higher net credit balances outstanding in these accounts.

Other income and expense–net was $1.6 million lower in 2005 compared to 2004. The decrease was primarily due to $1.0 million lower gains from company-owned life insurance, reflecting the liquidation of $17.6 million in cash surrender value of policies in 2004, and the absence of the equity component in the allowance for funds used during construction (AFUDC) reflecting lower construction work in progress balances.

Interest Charges–Net of Amounts Capitalized

Interest charges–net of amounts capitalized in 2006 was $2.0 million, or 5 percent, higher than in 2005, reflecting higher interest rates on short-term debt balances and slightly higher average balances of long-term debt outstanding during the period due to the issuance of $50 million in June 2005 and $25 million in December 2006. AFUDC reduced interest expense by $0.8 million in 2006, compared to reductions of $0.5 million in 2005 and $1.0 million in 2004. The increase in AFUDC in 2006 reflects higher construction work in progress balances. The decrease in AFUDC in 2005 reflects lower balances due to the completion in 2004 of our major South Mist Pipeline Extension project, which extended the pipeline from our Mist gas storage field to serve growing portions of our service area. The average interest crediting rate for AFUDC, comprised of short-term and long-term borrowing rates, as appropriate, was 4.7 percent in 2006, 3.1 percent in 2005 and 3.0 percent in 2004.

Income Tax Expense

Income tax expense totaled $36.2 million in 2006 compared to $32.7 million in 2005. The effective tax rate was 36.4 percent in 2006 compared to 36.0 percent in 2005. The higher 2006 effective tax rate partially reflects the expiration of a federal tax credit associated with Financial Corporation's investment in a low-income housing project (see Note 2, "Other") and non-taxable life insurance gains. Income tax expense increased by $6.2 million in 2005, as compared to total income tax expense of $26.5 million in 2004, and the effective tax rate increased 1.6 percent from an effective tax rate of 34.4 percent in 2004. The higher 2005 effective tax rate was primarily attributable to a decrease in tax benefits of $0.8 million resulting from a non-taxable gain on company-owned life insurance in 2004 and from $0.7 million in other tax adjustments recorded in 2004.

A recent interpretation (FIN 48) of SFAS No. 109, "Accounting for Uncertainty in Income taxes—an interpretation of FASB Statement No. 109," was issued by the FASB in July 2006 to address how companies should account for the tax benefits of timing and permanent income tax positions taken or expected to be taken in a tax return. See "Application of Critical Accounting Policies and Estimates—Accounting for Income Taxes," above and Note 1, "Recent Accounting Pronouncements."

## Financial Condition

### Capital Structure

Our goal is to maintain a target capital structure comprised of 45 to 50 percent common stock equity and 50 to 55 percent long-term and short-term debt. When additional capital is required, debt or equity securities are issued depending upon both the target capital structure and market conditions. These sources also are used to meet long-term debt redemption requirements and short-term commercial paper maturities (see "Liquidity and Capital Resources," below, and Notes 3, 5 and 6). Our consolidated capital structure was as follows:

| December 31, | 2006 | 2005 |
|---|---|---|
| Common stock equity | 48.1% | 47.2% |
| Long-term debt | 41.5% | 42.0% |
| Short-term debt, including current maturities of long-term debt | 10.4% | 10.8% |
| Total | 100.0% | 100.0% |

Achieving the target capital structure and maintaining sufficient liquidity are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs.

### Liquidity and Capital Resources

At December 31, 2006, we had $5.8 million in cash and cash equivalents compared to $7.1 million at December 31, 2005. Short-term liquidity is provided by cash from operations and from the sale of commercial paper notes, which are supported by committed bank lines of credit. We have available committed bank lines totaling $200 million with five commercial banks through September 30, 2010 (see "Lines of Credit," below, and Note 6). Short-term debt balances typically are reduced toward the end of the winter heating season as a significant amount of our current assets, primarily accounts receivable and gas inventories, are converted into cash.

Capital expenditures primarily relate to utility construction resulting from customer growth and system improvements (see "Cash Flows—Investing Activities," below). Certain contractual commitments under capital leases, operating leases, gas supply purchase contracts and other contracts require an adequate source of funding. These capital and contractual expenditures are financed through cash from operations and from the issuance of short-term debt, which is periodically refinanced through the sale of long-term debt or equity securities.

To provide long-term financing, we periodically issue and sell secured or unsecured debt, preferred stock or common stock. In April 2004, we issued $40 million of common stock and in June 2005 and December 2006, we issued $50 million and $25 million of secured medium-term notes, respectively. At December 31, 2006, we had $85 million available for future issuance of debt or equity securities under a universal shelf registration, which was previously approved by the OPUC (see "Financing Activities," below).

Neither our Mortgage and Deed of Trust nor the Indenture under which other long-term debt may be issued contain credit rating triggers or stock price provisions that require the acceleration of debt repayment. Also, there are no rating triggers or stock price provisions contained in contracts or other agreements with third parties, except for agreements with certain counterparties under our Financial Derivatives Policy, which may require the affected party to provide substitute collateral such as cash, guaranty or letters of credit if credit ratings are lowered to non-investment grade, or in some cases if the mark-to-market value exceeds a certain threshold.

Based on the availability of short-term credit facilities and our expectation of being able to issue long-term debt and equity securities, we believe there is sufficient liquidity to satisfy our anticipated cash requirements, including the contractual obligations and investing and financing activities discussed below.

Dividend Policy

We have paid quarterly dividends on our common stock in each year since the stock first was issued to the public in 1951. Annual common dividend payments have increased each year since 1956. The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. It is the intention of the Board of Directors to continue to pay cash dividends on common stock on a quarterly basis. However, the declarations and amounts of future dividends will be dependent upon our earnings, cash flows, financial condition and other factors.

Off-Balance Sheet Arrangements

Except for certain lease and purchase commitments (see “Contractual Obligations,” below), we have no material off-balance sheet financing arrangements.

Contractual Obligations

The following table shows our contractual obligations by maturity and type of obligation.

| | Payments Due in Years Ending December 31, | | | | | | |
|---|---|---|---|---|---|---|---|
| Thousands | 2007 | 2008 | 2009 | 2010 | 2011 | Thereafter | Total |
| Commercial paper | $100,100 | $ - | $ - | $ - | $ - | $ - | $ 100,100 |
| Long-term debt maturities | 29,500 | 5,000 | - | 35,000 | 10,000 | 467,000 | 546,500 |
| Interest on long-term debt | 34,396 | 33,632 | 33,417 | 33,406 | 30,858 | 341,592 | 507,301 |
| Pension funding obligation | 13,139 | 13,818 | 14,513 | 15,615 | 16,221 | 93,212 | 166,518 |
| Postretirement funding obligation | 1,571 | 1,596 | 1,626 | 1,685 | 1,753 | 9,002 | 17,233 |
| Capital leases | 317 | 233 | 84 | - | - | - | 634 |
| Operating leases | 4,200 | 4,100 | 4,100 | 4,100 | 4,100 | 35,300 | 55,900 |
| Gas purchase contracts[1] | 283,180 | 177,943 | 98,807 | 47,263 | 25,828 | 73,179 | 706,200 |
| Gas pipeline commitments | 81,024 | 70,848 | 64,988 | 66,085 | 70,059 | 198,863 | 551,867 |
| Other purchase commitments | 15,121 | 57 | - | - | - | - | 15,178 |
| Total | $562,548 | $307,227 | $217,535 | $203,154 | $158,819 | $1,218,148 | $2,667,431 |

[1] All gas purchase contract use price formulas tied to monthly index prices. Commitment amounts are based on index prices at December 31, 2006.

Other purchase commitments primarily consist of remaining balances under existing purchase orders. These and other contractual obligations are financed through cash from operations and from the issuance of short-term debt, which is periodically refinanced through the sale of long-term debt or equity securities.

Holders of certain long-term debt have put options that, if exercised, would require repurchases of up to $20 million principal amount in each of 2007, 2008 and 2009. If repurchased prior to maturity, then the interest obligation shown in the above table would be reduced in future years. The interest rate on the long-term debt issues with put options ranges between 6.52 percent and 7.05 percent.

In March 2004, our employees who are members of the Office and Professional Employees International Union, Local No. 11, approved a labor agreement (Joint Accord) covering wages, benefits and working conditions. This contract will expire on May 31, 2009.

Commercial Paper

Our primary source of short-term funds is from the sale of commercial paper notes. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas inventories and accounts receivable, short-term debt may also be used to temporarily fund capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by committed bank lines of credit (see "Lines of Credit," below). We had $100.1 million in commercial paper notes outstanding at December 31, 2006, compared to $126.7 million at December 31, 2005.

Lines of Credit

In September 2005, we entered into agreements for unsecured lines of credit totaling $200 million with five commercial banks, replacing the former $150 million credit facilities. The bank lines of credit are available and committed for a term of five years from October 1, 2005 to September 30, 2010. Our bank lines are used primarily as back-up support for the notes payable under our commercial paper borrowing program. Commercial paper provides the liquidity to meet our working capital and external financing requirements.

Under the terms of these bank lines, we pay upfront fees and annual commitment fees but are not required to maintain compensating bank balances. The interest rates on outstanding loans, if any, under these bank lines are based on then-current market interest rates. All principal and unpaid interest under the bank lines is due and payable on September 30, 2010.

The bank lines require that we maintain credit ratings with Standard & Poor's Rating Services (S&P) and Moody's Investors Service (Moody's) and notify the banks of any change in our senior unsecured debt ratings by such rating agencies. A change in our credit rating is not an event of default, nor is the maintenance of a specific minimum level of credit rating a condition of drawing upon the bank lines. However, interest rates on any loans outstanding under these bank lines are tied to our credit ratings, which would increase or decrease the cost of any loans under the bank lines when ratings are changed.

The bank lines also require us to maintain an indebtedness to total capitalization ratio of 65 percent or less. Failure to comply with this covenant would entitle the banks to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2006 and 2005.

Credit Ratings

The table below summarizes our credit ratings from two rating agencies, S&P and Moody's.

| | S&P | Moody's |
|---|---|---|
| Commercial paper (short-term debt) | A-1+ | P-1 |
| Senior secured (long-term debt) | AA- | A2 |
| Senior unsecured (long-term debt) | A+ | A3 |
| Ratings outlook | Stable | Stable |

On February 28, 2006, S&P raised the credit ratings on our senior secured long-term debt to "AA-" from "A+" and our senior unsecured long-term debt to "A+" from "A." S&P also raised the credit ratings on commercial paper to "A-1+" from "A-1." Both of the rating agencies have assigned us an investment grade rating. These credit ratings and ratings outlook are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell or hold our securities. Each rating should be evaluated independently of any other rating.

In August 2006, we elected to discontinue the credit rating service from Fitch Ratings (Fitch) for cost management reasons. At the time this service was cancelled, Fitch had assigned an A+ rating to our secured long-term debt, an A rating to our unsecured long-term debt and an F1 rating to our commercial paper program. Also, the ratings outlook from Fitch was stable.

Redemptions of Long-Term Debt

In June 2006, we redeemed $8.0 million of secured 6.05% Series B Medium-Term Notes (MTNs) at maturity.

In July 2005, we redeemed three series of maturing secured MTNs aggregating $15 million in principal amount. The series redeemed were the 6.34% Series B, the 6.38% Series B and the 6.45% Series B, each due in July 2005. The notes were redeemed with proceeds from the sales of $50 million in principal amount of secured MTNs in June 2005 (see "Cash Flows—Financing Activities," below).

In August 2005, we called for redemption all of our outstanding Convertible Debentures, 7-1/4% Series due 2012, at 100 percent of their principal amount plus accrued interest to the date of redemption. During 2005, debentures with an aggregate principal amount of $4.0 million were converted into shares of common stock on or prior to the redemption date at the rate of 50.25 shares for each $1,000 principal amount of debentures and $0.5 million of debentures were redeemed.

Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, changes in working capital requirements and other cash and non-cash adjustments to operating results. In 2006, our cash flow from net income and operating activity adjustments, excluding working capital changes, increased by $44.6 million, primarily due to a $31.0 million decrease in cash contributions to our qualified defined benefit pension plans and a $18.2 million increase in cash collections from deferred gas costs and improved operating results, partially offset by a decrease in deferred income tax benefits reflecting the expiration of higher tax benefits realized in 2004 from accelerated bonus depreciation. In 2005, the cash flow from net income and operating activity adjustments, excluding working capital changes, decreased by $25.9 million, primarily due to a decrease in deferred income tax benefits reflecting the expiration of higher tax benefits realized in 2004 from accelerated bonus depreciation and an increase in cash contributions to our qualified pension plans, partially offset by an increase in net income and cash from deferred gas costs.

The overall change in cash flow from operating activities in 2006 compared to 2005 was an increase of $69.5 million. The overall change in cash flow from operations was a decrease of $25.8 million in 2005 compared to 2004. The significant factors contributing to the cash flow changes between years are as follows:

*2006 compared to 2005:*

- an increase in net income added $5.3 million to cash flow;
- a decrease in cash of $26.0 million related to a deferred income tax benefit in 2006 compared to a deferred income tax expense in 2005;
- the change to regulatory liabilities in 2006 from regulatory receivables in 2005 related to deferred gas costs increased cash flow by $18.2 million, reflecting deferral activity between the two years with respect to purchased gas cost savings and off-system gas sales under our PGA tariff;
- cash increased by $31.0 million in 2006 compared to 2005 due to the 2005 cash contributions to our qualified defined benefit pension plans;
- an increase in cash in 2006 of $36.5 million due to a decrease in accounts receivable and accrued unbilled revenue related to warmer weather around year end;
- an increase of $27.7 million in cash resulting primarily from a decrease in gas inventory costs in 2006 compared to 2005;
- a decrease in income taxes receivable contributed $10.5 million to cash in 2006;
- a reduction in accounts payable decreased cash $54.5 million in 2006 primarily due to lower gas prices around year end;
- a reduction in prepayments increased cash $6.4 million in 2006; and
- an increase in deferred regulatory liabilities increased cash by $11.3 million in 2006.

*2005 compared to 2004:*

- an increase in net income added $7.6 million to cash flow;
- a decrease in deferred income tax expense in 2005, compared to a significant increase in 2004, decreased cash by $27.2 million, reflecting the expiration of higher tax benefits realized in 2004 from accelerated bonus depreciation;
- a small decrease in regulatory receivables in 2005, compared to a large increase in 2004 for deferred gas costs, increased cash flow by $17.8 million, reflecting deferral activity, including collections, between the two years with respect to purchase gas cost savings and off-system gas sales under our PGA tariff;
- cash contributions to our qualified defined benefit pension plan decreased cash flows by $22.7 million, primarily due to a $31.0 million pension contribution to those plans in 2005, compared to $8.3 million in 2004;
- an increase in deferred environmental costs decreased cash flow by $6.9 million, reflecting an increase in cash requirements for environmental remediation work during 2005 (see "Contingent Liabilities—Environmental Matters," below);

- a larger increase in accounts receivable reduced cash flow by $11.6 million, primarily reflecting the higher gas prices and the timing of customer account collections;
- a larger increase in accrued unbilled revenue reduced cash flow by $11.8 million, reflecting a combination of higher gas prices and colder weather in December 2005 compared to December 2004;
- an increase in inventories decreased cash flow by $4.1 million, primarily reflecting injections into storage at higher gas prices;
- a decrease in income taxes receivable increased cash flow by $9.7 million; and
- an increase in accounts payable increased cash flow by $16.4 million, primarily reflecting higher gas prices at year-end 2005.

We have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations (see "Liquidity and Capital Resources—Contractual Obligations," above, and Note 12).

Investing Activities

Cash requirements for investing activities in 2006 totaled $90.6 million, down slightly from $92.0 million in 2005. Cash requirements for the acquisition and construction of utility plant totaled $95.3 million in 2006, up from $89.3 million in 2005. The increase in cash requirements for utility construction in 2006 primarily reflects $12.5 million of capital expenditures in 2006 for an automated meter reading system, which will be completed in 2007.

Cash requirements for investing activities in 2005 totaled $92.0 million, down from $132.6 million in 2004. Cash requirements for the acquisition and construction of utility plant totaled $89.3 million, down from $138.3 million in 2004. The decrease in cash requirements for utility construction in 2005 reflects the completion in 2004 of our South Mist Pipeline Extension project, which extended the pipeline from our Mist gas storage field to serve growing portions of our service area. The total cost of the project was approximately $108.0 million, which includes amounts reflected in investing activities primarily over the 2002-2004 period. The cost of service associated with the final phase of the project, net of deferred tax benefits, was included in utility customer rates beginning in the fourth quarter of 2004.

Investments in our pipeline integrity management program were $11.0 million in 2006, compared to $6.1 million in 2005 and $1.6 million in 2004. These costs are estimated at approximately $50 million to $100 million over a ten-year period through 2012. The costs are accumulated over each 12-month period ending September 30, and the capitalized costs, subject to audit, are recovered through the annual PGA based on adjustments to rate base each year. The approved regulatory accounting and rate treatment for these costs extends through September 30, 2008, and may be reviewed for potential extension after that date.

Investments in non-utility property totaled $1.8 million in 2006, compared to $6.8 million in 2005 and $10.6 million in 2004. The lower investments in both 2006 and 2005 compared to 2004 were primarily due to the completion of expansion projects at our gas storage facilities in 2004 and partially in 2005.

In 2006, we received proceeds from the settlement of company-owned life insurance policy benefits totaling $4.0 million compared to $0.3 million in 2005. In 2004, we received proceeds from the surrender of certain life insurance policies as well as from policy benefit distributions totaling $17.6 million.

During the five-year period 2007 through 2011, utility construction expenditures are estimated at between $500 and $600 million. The estimated level of capital expenditures over the next five years reflects continued customer growth, gas storage development, technology improvements and utility system improvements, including requirements under the Pipeline Safety Improvement Act of 2002. Most of the required funds are expected to be internally generated over the five-year period and any remaining funding will be obtained through the issuance of long-term debt or equity securities, with short-term debt providing liquidity and bridge financing.

Our utility and non-utility capital expenditures for 2007 are estimated to total $110 million, including $27 million for customer growth, $21 million for system improvements, $13 million for equipment, facilities and information technology, $10 million for pipeline integrity costs, $5 million for an automated meter reading project, $14 million for utility and non-utility gas storage, and $20 million for construction overhead. These estimates do not include costs of the potential pipeline project with GTN or other investments that may be driven by our business process redesign (see "Strategic Opportunities," above).

In December 2003, the U.S. Department of Transportation's Office of Pipeline Safety (now the Pipeline Hazardous Materials Safety Administration) issued a rule that specifies the detailed requirements for transmission pipeline integrity management plans as mandated by the Pipeline Safety Act. See Part I., Item 1., "Pipeline Safety." We have met the first major milestones required by the Act and are on track to complete the next milestone, inspection of the highest risk 50 percent of our transmission pipelines, by the end of 2007.

Financing Activities

Cash used in financing activities in 2006 totaled $59.4 million, as compared to cash provided by financing in 2005 of $14.8 million. Factors contributing to the $74.2 million net change were the net change in short-term debt ($50.8 million), a lower amount of long-term debt issued during 2006 ($25.0 million) and the lower amount of equity financing in 2006 ($3.6 million), partially offset by a smaller redemption of long-term debt in 2006 compared to 2005 ($7.5 million).

Cash provided by financing activities in 2005 totaled $14.8 million, compared to $28.3 million in 2004. Factors contributing to the $13.4 million decrease were the redemption of long-term debt and convertible debentures ($15.5 million), the increased repurchases of common stock in 2005 ($14.4 million) and the lower amount of equity financing in 2005 ($39.1 million), partially offset by the issuance of $50 million of secured MTNs during 2005 and the net change in short-term debt ($6.9 million).

In December 2006, we sold $25 million of 5.15% Series B, secured MTNs due 2016 and used the proceeds to reduce short-term indebtedness and to fund utility construction.

In 2005, we sold $40 million of 4.70% Series B, secured MTNs due 2015 and $10 million of 5.25% Series B, secured MTNs due 2035, and used the proceeds to redeem long-term debt, to reduce short-term indebtedness and to make investments in utility plant.

In April 2004, we issued and sold 1,290,000 shares of our common stock in an underwritten public offering, and used the net proceeds of $38.5 million to reduce short-term indebtedness and to fund, in part, our utility construction program.

In 2000, we announced a program to repurchase up to 2 million shares, or up to $35 million in value, of our common stock through a repurchase program, and in 2006 that program was modified to 2.6 million shares and $85 million in value and extended through May 2007. The purchases are made in the open market or through privately negotiated transactions. Repurchases pursuant to the program in 2006 totaled 395,500 shares or $16.0 million and in 2005 were 410,200 shares, or $14.9 million. No shares were purchased pursuant to the program in 2004. Since the program's inception, we have repurchased 1,161,100 shares of common stock at a total cost of $39.1 million (see Part II, Item 5, "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities," above).

In 2006, we produced free cash flow of $19.7 million, compared to 2005 and 2004 when we had negative free cash flows of $49.3 million and $62.8 million, respectively. Free cash flow is the amount of cash left over after the payment of all cash expenses, capital expenditures (investment activities) and dividends. Free cash flow is a non-GAAP financial measure, but we believe this supplemental information enables the reader of the financial statements to better understand our cash generating ability and to benefit from seeing cash flow results from management's perspective in addition to the traditional GAAP presentation. We monitor free cash flow as one measure of our return on investments. Provided below is a reconciliation from cash provided by operations (GAAP basis) to our non-GAAP free cash flow.

| Thousands (year ended December 31) | 2006 | 2005 | 2004 |
|---|---|---|---|
| Cash provided by operating activities | $148,566 | $ 79,066 | $ 104,899 |
| Cash used in investing activities | (90,567) | (92,008) | (132,631) |
| Cash divided payments on common stock | (38,298) | (36,376) | (35,105) |
| Free cash flow | $ 19,701 | $(49,318) | $ (62,837) |

The free cash flow information presented above is not intended to be a substitute for, nor is it meant to be a better measure of, cash flow results prepared in accordance with GAAP. In addition, the non-GAAP measure we provide may be calculated differently by other companies that present a similar non-GAAP financial measure for free cash flow.

Pension Cost and Funding Status of Qualified Retirement Plans

Pension costs are determined in accordance with SFAS No. 87, "Employers' Accounting for Pensions" (see "Application of Critical Accounting Policies—Accounting for Pensions," above). Pension costs are allocated between operations and maintenance expense and capital accounts based on employee payroll distributions.

Pension costs for our two qualified defined benefit pension plans totaled $8.2 million in 2006, an increase of $1.3 million over 2005. The increase in 2006 pension costs was primarily due to the lower discount rate (5.75 percent in 2006 compared to 6.00 percent in 2005) and the adoption of new mortality rate assumptions as of December 31, 2005.

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Generally, it is our policy to contribute at least the minimum amount required by Internal Revenue Code regulations and the Employee Retirement Income Security Act of 1974. It is also our intent to contribute additional amounts sufficient on a sound actuarial basis to maintain funding targets and provide for the payment of future benefits under the plans.

During 2005, we contributed $31 million to our two qualified defined benefit plans, but no additional contributions were made to these plans in 2006. Although we were not required to make cash contributions in either 2005 or 2006 based on minimum funding requirements, we contributed to these plans in 2005 to maintain a target funding level based on plan benefit obligations.

The fair market value of the assets in these two plans increased to $236.5 million at December 31, 2006, up from $218.6 million at December 31, 2005. The increase included $31.5 million in investment gains, which were offset in part by $12.1 million in withdrawals to pay benefits and $1.4 million in eligible expenses of the two plans. The present value of benefit obligations under the two plans increased from $254 million at December 31, 2005 to $255 million at December 31, 2006. The two qualified defined benefit pension plans were underfunded in aggregate by approximately $18.9 million at December 31, 2006.

Pension costs for the plans totaled $6.9 million in 2005, compared to $6.6 million in 2004. The increase in pension costs in 2005 was primarily due to the lower discount rate (6.00 percent in 2005 compared to 6.25 percent in 2004), partially offset by higher earnings on additional cash contributions to the plans.

At December 31, 2005, the fair market value of the qualified defined benefit pension plans' assets totaled $219 million, up from $187 million at December 31, 2004. The increase included $13.5 million in investment gains and employer contributions of $31 million, which were offset in part by $11.8 million in withdrawals to pay benefits and $0.9 million in eligible expenses of the two plans. The present value of benefit obligations under the two plans increased from $209 million to $254 million during 2005, primarily due to the adoption of a new mortality table to reflect the increased life expectancies of plan participants. The two plans were underfunded in aggregate by about $36 million at December 31, 2005.

Despite the increase in pension costs and the current underfunded status of the plans, we believe the plans to be adequately funded and that we will be able to continue to maintain appropriate funding levels. The annualized returns for the past one, five and 10 years ended December 31, 2006 were 14.9 percent, 10.1 percent and 10.2 percent, respectively. We do not expect our current or future cash contribution requirements to the two plans to have a material adverse effect on our liquidity or financial condition (see Note 7). Effective January 1, 2007, we closed our Non-Bargaining Unit Plan to newly-hired or rehired employees.

### Ratios of Earnings to Fixed Charges

For the years ended December 31, 2006, 2005 and 2004, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 3.40, 3.32 and 3.02, respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with SFAS No. 5, "Accounting for Contingencies," (see "Application of Critical Accounting Policies and Estimates—Contingencies," above). At December 31, 2006, a cumulative $27.8 million in environmental costs was recorded as a regulatory asset, including $19.1 million of costs paid to-date and $8.7 million of estimated accrued future environmental costs. If it is determined that both the insurance recovery and future customer rate recovery of such costs is not probable, then the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities, see Note 12.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

We are exposed to various forms of market risk including commodity supply risk, weather risk and interest rate risk. The following describes our exposure to these risks.

Commodity Supply Risk

We enter into short-term, medium-term and long-term natural gas supply contracts, along with associated short-, medium- and long-term transportation capacity contracts. Historically, we have taken physical delivery of at least the minimum quantities specified in our natural gas supply contracts. These contracts are primarily index-based and subject to annual re-pricing, a process that is intended to reflect anticipated market price trends during the next year. Our PGA mechanisms in Oregon and Washington provide for the recovery from customers of actual commodity costs, except that, for Oregon customers, we absorb 33 percent of the higher cost of gas sold, or retain 33 percent of the lower cost, in either case as compared to the annual PGA price built into customer rates.

Market risks related to potential adverse changes in commodity prices, foreign exchange rates or counterparty credit quality in relation to these financial and physical contracts are discussed below.

Commodity Price Risk

Natural gas commodity prices are subject to fluctuations due to unpredictable factors including weather, pipeline transportation congestion and other factors that affect short-term supply and demand. Commodity-price swap and call option contracts (financial hedge contracts) are used to convert certain natural gas supply contracts from floating prices to fixed prices. These financial hedge contracts are generally included in our annual PGA filing, subject to a prudency review. At December 31, 2006 and 2005, notional amounts under these commodity swap and call option contracts totaled $349.7 million and $470.5 million, respectively. If all of the commodity-price swap and call option contracts had been settled on December 31, 2006, a regulatory loss of $37.8 million would have been realized and deferred (see Note 11). 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 two years. The $37.8 million unrealized loss is an estimate of future cash flows that are expected to be paid as follows: $30.8 million in 2007 and $7.0 million in 2008. The amount realized will change based on market prices at the time contract settlements are fixed.

Foreign Currency Risk

The costs of certain natural gas commodity supplies and certain pipeline services purchased from Canadian suppliers are subject to changes in the value of the Canadian currency in relation to the U.S. currency. Foreign currency forward contracts are used to hedge against fluctuations in exchange rates with respect to the purchases of natural gas from Canadian suppliers. At December 31, 2006 and 2005, notional amounts under foreign currency forward contracts totaled $5.0 million and $19.9 million, respectively. As of December 31, 2006, no foreign currency forward contracts extended beyond December 31, 2007. If all of the foreign currency forward contracts had been settled on December 31, 2006, a loss of $0.1 million would have been realized (see Note 11).

Credit Risk

***Credit exposure to suppliers***. Certain suppliers that sell us gas have either relatively low credit ratings or are not rated by major credit rating agencies. To manage this supply risk, we purchase gas from a number of different suppliers, with no single supplier accounting for more than 20 percent of our total purchases for a given monthly period. We evaluate and continuously monitor suppliers' creditworthiness and maintain the ability to require additional financial assurances, including deposits, letters of credit or surety bonds in case a supplier defaults. In the event of a supplier's failure to deliver contracted volumes of gas, the regulated utility would need to replace those volumes at prevailing market prices, which may be higher or lower than the original transaction prices. We believe these costs would be subject to the PGA sharing mechanism discussed above. Since most of our commodity supply contracts are priced at the monthly market index price, and we have significant storage flexibility, we believe that it is unlikely that a supplier default would have a material adverse effect on our financial condition or results of operations.

***Credit exposure to financial derivative counterparties***. Based on estimated fair value, our credit exposure to financial derivative counterparties relating to commodity swap and call option contracts was a negative $41.0 million at December 31, 2006. Our Financial Derivatives Policy requires counterparties to have a minimum credit rating at the time the derivative instrument is entered into, and the policy specifies limits on the contract amount and duration based on each counterparty's credit rating. There were no credit rating downgrades for any of our counterparties during 2006.

The following table summarizes our credit exposure, based on estimated fair value, and the corresponding counterparty credit ratings. The table uses credit ratings from S&P and Moody's, reflecting the higher of S&P or Moody's rating, or a middle rating if the entity is split-rated more than one rating level:

| | Financial Derivative Position by Credit Rating Unrealized Fair Value Gain (Loss) | |
|---|---|---|
| Thousands | Dec. 31, 2006 | Dec. 31, 2005 |
| AAA/Aaa | $ - | $ - |
| AA/Aa | (40,955) | 172,315 |
| A/A | - | - |
| BBB/Baa | - | 3,346 |
| Total | $(40,955) | $175,661 |

***Credit exposure to customers***. Increases in the price of natural gas are expected to increase our credit exposure to customers. However, in the short term, market prices have moderated and resulted in some of our large industrial customers changing from sales services to transportation service. Under sales service, the customer purchases both its gas commodity supply and transportation service from us. Under transportation service, the customer purchases its commodity supplies from an independent third party, with us only providing the transportation service for delivery of that gas to the customer's premise. As a result of this migration from sales service to transportation service, our credit exposure to large industrial customers is expected to moderate. We monitor and manage the credit exposure of our industrial customers through credit policies and procedures, which are designed to reduce credit risk. These policies and procedures include an ongoing review of credit risks, including changes in the services provided to industrial customers as well as changes in market conditions and customers' credit quality. Changes in credit risk may require us to obtain additional assurance, such as deposits, letters of credit, guarantees and prepayments to reduce our credit exposure.

We also monitor and manage the credit exposure of our residential and commercial customers. This credit risk is largely mitigated by the nature of our regulated business and reasonably short collection terms, as well as by the consistent application of our credit policies and procedures.

Weather Risk

We are exposed to weather risk primarily from our regulated utility business. A large percentage of our utility margin is volume driven, and current rates are based on an assumption of average weather. In 2003, the OPUC approved a weather normalization mechanism for residential and commercial customers. This mechanism affects customer bills between December 1 through May 15 of each winter heating season, increasing or decreasing the margin component of customers' rates to reflect "average" weather using the 25-year average temperature for each day of the billing period. The mechanism is intended to stabilize the recovery of our utility's fixed costs and reduce fluctuations in customers' bills due to colder or warmer than average weather. Customers in Oregon are allowed to opt out of the weather normalization mechanism. As of December 31, 2006, about 9 percent of our Oregon customers had opted out. In addition to the Oregon customers opting out, our Washington residential and commercial customers account for approximately 10 percent of our total customer base and are not covered by weather normalization. The combination of Oregon and Washington customers not covered by a weather normalization mechanism is less than 20 percent of all residential and commercial customers.

Interest Rate Risk

We are exposed to interest rate risk associated with new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. Interest rate risk is managed through the issuance of fixed-rate debt with varying maturities. We may also enter into financial derivative instruments, including interest rate swaps, locks, options and other hedge products, to manage and mitigate interest rate exposure. At December 31, 2006 and 2005, we had no variable-rate long-term debt and no financial derivative instruments to hedge interest rates. Holders of certain long-term debt have put options that, if exercised, would accelerate maturities by \$20 million in each of 2007, 2008 and 2009 (see Note 5 and Note 10).

## Forward-Looking Statements

This report and other presentations made by us from time to time may contain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include statements concerning plans, objectives, goals, strategies, future events or performance, and other statements that are other than statements of historical facts. Our expectations, beliefs and projections are expressed in good faith and are believed to have a reasonable basis. However, each forward-looking statement involves uncertainties and is qualified in its entirety by reference to the following important factors, among others, that could cause our actual results to differ materially from those projected, including:

- prevailing state and federal governmental policies and regulatory actions, including those of the OPUC and the WUTC, 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, present or prospective wholesale and retail competition, changes in tax laws and policies and changes in and compliance with environmental and safety laws, regulations, policies and orders, and laws, regulations and orders with respect to the maintenance of pipeline integrity;

- implementation by the OPUC of final rules interpreting Oregon legislation intended to ensure that utilities do not collect more income taxes in rates than they actually pay to government entities;
- weather conditions, pandemic events and other natural phenomena, including earthquakes or other geohazard events;
- unanticipated population growth or decline and changes in market demand caused by changes in demographic or customer consumption patterns;
- competition for retail and wholesale customers;
- market conditions and pricing of natural gas relative to other energy sources;
- risks relating to the creditworthiness of customers, suppliers and financial derivative counterparties;
- risks relating to our dependence on a single pipeline transportation provider for natural gas supply;
- risks relating to property damage associated with a pipeline safety incident, as well as risks resulting from uninsured damage to our property, intentional or otherwise;
- unanticipated changes that may affect our liquidity or access to capital markets;
- risks relating to the execution of our business process redesign;
- our ability to maintain effective internal controls over financial reporting in compliance with Section 404 of the Sarbanes-Oxley Act of 2002;
- unanticipated changes in interest or foreign currency exchange 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;
- changes in estimates of potential liabilities relating to environmental contingencies;
- unanticipated changes in future liabilities relating to employee benefit plans, including changes in key assumptions;
- capital market conditions, including their effect on the fair value of pension assets and on pension and other postretirement benefit costs;
- potential inability to obtain permits, rights of way, easements, leases or other interests or other necessary authority to construct pipelines, develop storage or complete other system expansions; and
- legal and administrative proceedings and settlements.

All subsequent forward-looking statements, whether written or oral and whether made by or on behalf of NW Natural, also are expressly qualified by these cautionary statements. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time and it is not possible for us to predict all such factors, nor can we assess the impact of each such factor or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

## Table of Contents



Supplemental Schedules Omitted

All other schedules are omitted because of the absence of the conditions under which they are required or because the required information is included elsewhere in the financial statements.

## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America (GAAP). Our internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions involving company assets;

(ii) provide reasonable assurance that transactions are recorded as necessary to permit the preparation of financial statements in accordance with GAAP, and that receipts and expenditures are being made only in accordance with authorizations of management and the Board of Directors; and

(iii) provide reasonable assurance regarding prevention or timely detection of the unauthorized acquisition, use or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of NW Natural's internal control over financial reporting as of December 31, 2006. In making this assessment, management used the framework set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework*.

Based on our assessment and those criteria, management has concluded that NW Natural maintained effective internal control over financial reporting as of December 31, 2006.

Management's assessment of the effectiveness of internal control over financial reporting as of December 31, 2006 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in this annual report.

/s/ Mark S. Dodson
Mark S. Dodson
President and Chief Executive Officer

/s/ David H. Anderson
David H. Anderson
Senior Vice President and Chief Financial Officer

February 28, 2007

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Board of Directors and Shareholders of
Northwest Natural Gas Company:

We have completed integrated audits of Northwest Natural Gas Company's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the accompanying table of contents present fairly, in all material respects, the financial position of Northwest Natural Gas Company and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying table of contents presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements 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 of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for share based compensation in 2006 and the manner in which it accounts for defined benefit pension and other postretirement plans effective December 31, 2006.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Controls Over Financial Reporting appearing under Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control—Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting 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 effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and the board of directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

PricewaterhouseCoopers LLP
Portland, Oregon
February 28, 2007

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF INCOME

| Thousands, except per share amounts (year ended December 31) | 2006 | 2005 | 2004 |
|---|---|---|---|
| Operating revenues: | | | |
| Gross operating revenues | $1,013,172 | $910,486 | $707,604 |
| Less: Cost of sales | 648,156 | 563,860 | 399,244 |
| Revenue taxes | 24,840 | 21,633 | 16,865 |
| Net operating revenues | 340,176 | 324,993 | 291,495 |
| Operating expenses: | | | |
| Operations and maintenance | 114,560 | 113,216 | 102,155 |
| General taxes | 24,419 | 23,185 | 21,943 |
| Depreciation and amortization | 64,435 | 61,645 | 57,371 |
| Total operating expenses | 203,414 | 198,046 | 181,469 |
| Income from operations | 136,762 | 126,947 | 110,026 |
| Other income and expense - net | 2,134 | 1,205 | 2,828 |
| Interest charges - net of amounts capitalized | 39,247 | 37,283 | 35,751 |
| Income before income taxes | 99,649 | 90,869 | 77,103 |
| Income tax expense | 36,234 | 32,720 | 26,531 |
| Net income | $ 63,415 | $ 58,149 | $ 50,572 |
| Average common shares outstanding: | | | |
| Basic | 27,540 | 27,564 | 27,016 |
| Diluted | 27,657 | 27,621 | 27,283 |
| Earnings per share of common stock: | | | |
| Basic | $ 2.30 | $ 2.11 | $ 1.87 |
| Diluted | $ 2.29 | $ 2.11 | $ 1.86 |

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See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

| Thousands (December 31) | 2006 | 2005 |
|---|---|---|
| Assets: | | |
| Plant and property: | | |
| Utility plant | $1,963,498 | $1,875,444 |
| Less accumulated depreciation | 574,093 | 536,867 |
| Utility plant - net | 1,389,405 | 1,338,577 |
| Non-utility property | 42,652 | 40,836 |
| Less accumulated depreciation and amortization | 6,916 | 5,990 |
| Non-utility property - net | 35,736 | 34,846 |
| Total plant and property | 1,425,141 | 1,373,423 |
| Current assets: | | |
| Cash and cash equivalents | 5,767 | 7,143 |
| Accounts receivable | 82,070 | 84,418 |
| Accrued unbilled revenue | 87,548 | 81,512 |
| Allowance for uncollectible accounts | (3,033) | (3,067) |
| Regulatory assets | 31,509 | 3,879 |
| Fair value of non-trading derivatives | 5,109 | 163,759 |
| Inventories: | | |
| Gas | 68,576 | 77,256 |
| Materials and supplies | 9,552 | 8,905 |
| Income taxes receivable | - | 13,234 |
| Prepayments and other current assets | 21,695 | 54,309 |
| Total current assets | 308,793 | 491,348 |
| Investments, deferred charges and other assets: | | |
| Regulatory assets | 164,771 | 94,972 |
| Fair value of non-trading derivatives | 1,448 | 14,894 |
| Other investments | 47,985 | 58,451 |
| Other | 8,718 | 9,216 |
| Total investments, deferred charges and other assets | 222,922 | 177,533 |
| Total assets | $1,956,856 | $2,042,304 |

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See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

| Thousands (December 31) | 2006 | 2005 |
|---|---|---|
| Capitalization and liabilities: | | |
| Capitalization: | | |
| Common stock | $ 371,127 | $ 87,334 |
| Premium on common stock | - | 296,471 |
| Earnings invested in the business | 230,774 | 205,687 |
| Unearned stock compensation | - | (650) |
| Accumulated other comprehensive income (loss) | (2,356) | (1,911) |
| Total common stock equity | 599,545 | 586,931 |
| Long-term debt | 517,000 | 521,500 |
| Total capitalization | 1,116,545 | 1,108,431 |
| Current liabilities: | | |
| Notes payable | 100,100 | 126,700 |
| Long-term debt due within one year | 29,500 | 8,000 |
| Accounts payable | 113,579 | 135,287 |
| Taxes accrued | 21,230 | 12,725 |
| Interest accrued | 2,924 | 2,918 |
| Regulatory liabilities | 11,919 | 163,660 |
| Fair value of non-trading derivatives | 38,772 | 99 |
| Other current and accrued liabilities | 21,455 | 29,916 |
| Total current liabilities | 339,479 | 479,305 |
| Deferred credits and other liabilities: | | |
| Deferred income taxes and investment tax credits | 210,084 | 227,400 |
| Regulatory liabilities | 202,982 | 180,827 |
| Pension and other postretirement benefit liabilities | 52,690 | 17,323 |
| Fair value of non-trading derivatives | 11,031 | 6,777 |
| Other | 24,045 | 22,241 |
| Total deferred credits and other liabilities | 500,832 | 454,568 |
| Commitments and contingencies (see Note 12) | - | - |
| Total capitalization and liabilities | $1,956,856 | $2,042,304 |

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See Notes to Consolidated Financial Statements.

# NORTHWEST NATURAL GAS COMPANY
# CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

| Thousands | Common Stock and Premium | Earnings Invested in the Business | Unearned Stock Compensation | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity | Comprehensive Income |
|---|---|---|---|---|---|---|
| Balance at Dec. 31, 2003 | $338,008 | $170,053 | $(729) | $(1,016) | $506,316 | |
| Net Income | - | 50,572 | - | - | 50,572 | $50,572 |
| Minimum pension liability adjustment - net of tax | - | - | - | (802) | (802) | (802) |
| Purchases of restricted stock | (55) | (51) | (431) | - | (537) | |
| Restricted stock amortizations | - | - | 298 | - | 298 | |
| Dividends paid on common stock | - | (35,105) | - | - | (35,105) | |
| Tax benefits from employee stock option plan | 872 | - | - | - | 872 | |
| Issuance of common stock | 47,148 | - | - | - | 47,148 | |
| Convertible debentures | 1,292 | - | - | - | 1,292 | |
| Common stock expense | - | (1,537) | - | - | (1,537) | |
| Balance at Dec. 31, 2004 | 387,265 | 183,932 | (862) | (1,818) | 568,517 | $49,770 |
| Net Income | - | 58,149 | - | - | 58,149 | $58,149 |
| Minimum pension liability adjustment - net of tax | - | - | - | (93) | (93) | (93) |
| Restricted stock amortizations | - | - | 212 | - | 212 | |
| Dividends paid on common stock | - | (36,376) | - | - | (36,376) | |
| Tax benefits from employee stock option plan | 220 | - | - | - | 220 | |
| Issuance of common stock | 7,266 | - | - | - | 7,266 | |
| Common stock repurchased | (14,945) | - | - | - | (14,945) | |
| Convertible debentures | 3,999 | - | - | - | 3,999 | |
| Common stock expense | - | (18) | - | - | (18) | |
| Balance at Dec. 31, 2005 | 383,805 | 205,687 | (650) | (1,911) | 586,931 | $58,056 |
| Net Income | - | 63,415 | - | - | 63,415 | $63,415 |
| Minimum pension liability adjustment - net of tax | - | - | - | (81) | (81) | (81) |
| Recognition of non-qualified employee benefit plan liability, net of tax | | | | (364) | (364) | |
| Restricted stock amortizations | 298 | - | - | - | 298 | |
| Dividends paid on common stock | - | (38,298) | - | - | (38,298) | |
| Tax benefits from employee stock option plan | 317 | - | - | - | 317 | |
| Stock-based compensation | 555 | - | - | - | 555 | |
| Restricted stock reclassification | (650) | - | 650 | - | - | |
| Issuance of common stock | 2,773 | - | - | - | 2,773 | |
| Common stock repurchased | (15,971) | - | - | - | (15,971) | |
| Common stock expense | - | (30) | - | - | (30) | |
| Balance at Dec. 31, 2006 | $371,127 | $230,774 | $ - | $(2,356) | $599,545 | $63,334 |

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See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

| Thousands (year ended December 31) | 2006 | 2005 | 2004 |
|---|---|---|---|
| Operating activities: | | | |
| Net income | $ 63,415 | $ 58,149 | $ 50,572 |
| Adjustments to reconcile net income to cash provided by operations: | | | |
| Depreciation and amortization | 64,435 | 61,645 | 57,371 |
| Deferred income taxes and investment tax credits | (16,440) | 9,551 | 36,713 |
| Undistributed earnings from equity investments | (191) | (57) | (181) |
| Deferred gas costs - net | 20,752 | 2,577 | (15,178) |
| Gain on sale of non-utility investments | (495) | - | - |
| Income from life insurance investments | (2,609) | (1,873) | (2,855) |
| Contributions to qualified defined benefit pension plans | - | (31,000) | (8,261) |
| Non-cash expenses related to qualified defined benefit pension plans | 5,500 | 4,532 | 4,322 |
| Deferred environmental expenditures | (6,675) | (9,132) | (2,215) |
| Deferred regulatory costs and other | 14,533 | 3,243 | 3,289 |
| Changes in working capital: | | | |
| Accounts receivable and accrued unbilled revenue - net | (3,722) | (40,262) | (16,885) |
| Inventories of gas, materials and supplies | 8,033 | (19,684) | (15,618) |
| Income taxes receivable | 13,234 | 2,736 | (6,984) |
| Prepayments and other current assets | 2,952 | (3,439) | 245 |
| Accounts payable | (21,708) | 32,809 | 16,449 |
| Accrued interest and taxes | 8,511 | 2,504 | 1,536 |
| Other current and accrued liabilities | (959) | 6,767 | 2,579 |
| Cash provided by operating activities | 148,566 | 79,066 | 104,899 |
| Investing activities: | | | |
| Investment in utility plant | (95,307) | (89,259) | (138,347) |
| Investment in non-utility property | (1,773) | (6,842) | (10,568) |
| Proceeds from sale of non-utility investments | 2,517 | 3,001 | - |
| Proceeds from life insurance | 4,009 | 296 | 17,575 |
| Other | (13) | 796 | (1,291) |
| Cash used in investing activities | (90,567) | (92,008) | (132,631) |
| Financing activities: | | | |
| Common stock issued, net of expenses | 3,913 | 7,486 | 46,616 |
| Common stock repurchased | (15,971) | (14,945) | (537) |
| Long-term debt issued | 25,000 | 50,000 | - |
| Long-term debt retired | (8,000) | (15,528) | - |
| Change in short-term debt | (26,600) | 24,200 | 17,300 |
| Cash dividend payments on common stock | (38,298) | (36,376) | (35,105) |
| Other | 581 | - | - |
| Cash (used in) provided by financing activities | (59,375) | 14,837 | 28,274 |
| (Decrease) increase in cash and cash equivalents | (1,376) | 1,895 | 542 |
| Cash and cash equivalents - beginning of period | 7,143 | 5,248 | 4,706 |
| Cash and cash equivalents - end of period | $ 5,767 | $ 7,143 | $ 5,248 |
| Supplemental disclosure of cash flow information: | | | |
| Interest paid | $ 39,294 | $ 36,974 | $ 36,061 |
| Income taxes paid | $ 31,270 | $ 28,479 | $ 2,500 |
| Supplemental disclosure of non-cash financing activities: | | | |
| Conversions to common stock: | | | |
| 7-¼ % Series of Convertible Debentures | $ - | $ 3,999 | $ 1,292 |

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See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

| Thousands (December 31) | 2006 | | 2005 | |
|---|---|---|---|---|
| Common stock equity: | | | | |
| Common stock | $ 371,127 | | $ 87,334 | |
| Premium on common stock | - | | 296,471 | |
| Earnings invested in the business | 230,774 | | 205,687 | |
| Unearned compensation | - | | (650) | |
| Accumulated other comprehensive income (loss) | (2,356) | | (1,911) | |
| Total common stock equity | 599,545 | 54% | 586,931 | 53% |
| Long-term debt: | | | | |
| Medium-Term Notes | | | | |
| First Mortgage Bonds: | | | | |
| 6.050% Series B due 2006 | - | | 8,000 | |
| 6.310% Series B due 2007 | 20,000 | | 20,000 | |
| 6.800% Series B due 2007 | 9,500 | | 9,500 | |
| 6.500% Series B due 2008 | 5,000 | | 5,000 | |
| 4.110% Series B due 2010 | 10,000 | | 10,000 | |
| 7.450% Series B due 2010 | 25,000 | | 25,000 | |
| 6.665% Series B due 2011 | 10,000 | | 10,000 | |
| 7.130% Series B due 2012 | 40,000 | | 40,000 | |
| 8.260% Series B due 2014 | 10,000 | | 10,000 | |
| 4.700% Series B due 2015 | 40,000 | | 40,000 | |
| 5.150% Series B due 2016 | 25,000 | | - | |
| 7.000% Series B due 2017 | 40,000 | | 40,000 | |
| 6.600% Series B due 2018 | 22,000 | | 22,000 | |
| 8.310% Series B due 2019 | 10,000 | | 10,000 | |
| 7.630% Series B due 2019 | 20,000 | | 20,000 | |
| 9.050% Series A due 2021 | 10,000 | | 10,000 | |
| 5.620% Series B due 2023 | 40,000 | | 40,000 | |
| 7.720% Series B due 2025 | 20,000 | | 20,000 | |
| 6.520% Series B due 2025 | 10,000 | | 10,000 | |
| 7.050% Series B due 2026 | 20,000 | | 20,000 | |
| 7.000% Series B due 2027 | 20,000 | | 20,000 | |
| 6.650% Series B due 2027 | 20,000 | | 20,000 | |
| 6.650% Series B due 2028 | 10,000 | | 10,000 | |
| 7.740% Series B due 2030 | 20,000 | | 20,000 | |
| 7.850% Series B due 2030 | 10,000 | | 10,000 | |
| 5.820% Series B due 2032 | 30,000 | | 30,000 | |
| 5.660% Series B due 2033 | 40,000 | | 40,000 | |
| 5.250% Series B due 2035 | 10,000 | | 10,000 | |
| | 546,500 | | 529,500 | |
| Less long-term debt due within one year | 29,500 | | 8,000 | |
| Total long-term debt | 517,000 | 46% | 521,500 | 47% |
| Total capitalization | $1,116,545 | 100% | $1,108,431 | 100% |

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See Notes to Consolidated Financial Statements.

**NORTHWEST NATURAL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

## 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

### Organization and Principles of Consolidation

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), our regulated gas distribution business and our regulated gas storage business and a non-regulated wholly-owned subsidiary business, NNG Financial Corporation (Financial Corporation).

In this report, the term “utility” is used to describe the regulated gas distribution business and the term “non-utility” is used to describe the gas storage business and other non-regulated activities (see Note 2). Intercompany accounts and transactions have been eliminated.

Investments in corporate joint ventures and partnerships in which our ownership interest is 50 percent or less and over which we do not exercise control are accounted for by the equity method or the cost method (see Note 9).

Certain prior year balances on our consolidated balance sheet have been reclassified to conform with the current presentation. These reclassifications had no impact on our consolidated results of operations, financial condition or cash flows.

### Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (GAAP) requires management to make estimates and assumptions that affect reported amounts in the consolidated financial statements and accompanying notes. Actual amounts could differ from those estimates and changes would be reported in future periods. Management believes that the estimates and assumptions used are reasonable.

### Industry Regulation

Our principal business is the distribution of natural gas, which is regulated by the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC). Accounting records and practices of the regulated business conform to the requirements and uniform system of accounts prescribed by these regulatory authorities in accordance with Statement of Financial Accounting Standards (SFAS) No. 71, “Accounting for the Effects of Certain Types of Regulation.” The utility business segment is authorized by the OPUC and the WUTC to earn a reasonable return on invested capital.

In applying SFAS No. 71, we capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the OPUC or WUTC in general rate or expense deferral proceedings, to provide for recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge.

At December 31, 2006 and 2005, the amounts deferred as regulatory assets and liabilities were as follows:

| | Current | | Non-Current | |
|---|---|---|---|---|
| Thousands | 2006 | 2005 | 2006 | 2005 |
| Regulatory assets: | | | | |
| Gas costs receivable | $ - | $ 2,890 | $ - | $ 4,084 |
| Unrealized loss on non-trading derivatives[3] | 30,798 | - | 9,584 | - |
| Income tax asset | - | - | 67,141 | 65,843 |
| Pension and other postretirement benefit obligations[1] | - | - | 54,425 | - |
| Environmental costs - paid[2] | - | - | 19,113 | 12,439 |
| Environmental costs - accrued but not yet paid[2] | - | - | 8,760 | 6,440 |
| Other | 711 | 989 | 5,748 | 6,166 |
| Total regulatory assets | $31,509 | $ 3,879 | $164,771 | $ 94,972 |
| Regulatory liabilities: | | | | |
| Gas costs payable | $ 737 | $ - | $ 13,041 | $ - |
| Unrealized gain on non-trading derivatives[3] | - | 163,660 | - | 8,117 |
| Accrued asset removal costs | - | - | 187,422 | 169,927 |
| Other | 11,182 | - | 2,519 | 2,783 |
| Total regulatory liabilities | $11,919 | $163,660 | $202,982 | $180,827 |

1 Certain pension and other postretirement benefit obligations required by SFAS No. 158 are approved for regulatory deferral. Such amounts are recoverable in rates, including an interest component, when recognized in net periodic benefit cost (see Note 7.)

2 Environmental costs are related to sites that are approved for regulatory deferral. We earn the authorized rate of return as a carrying charge on amounts paid, but the amounts accrued but not yet paid do not earn a rate of return or a carrying charge until expended.

3 Unrealized gain or loss on non-trading derivatives do not earn a rate of return or a carrying charge. These amounts, when realized at settlement, are recoverable through utility rates as part of the PGA mechanism.

We believe that continued application of SFAS No. 71 for regulated activities is appropriate and consistent with the current regulatory environment, and that all regulated assets and liabilities at December 31, 2006 and 2005 are recoverable or refundable through future utility rates. We review all regulatory assets at least annually for recoverability. If we should determine that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of SFAS No. 71, then we would be required to write off the net unrecoverable balances against earnings.

## New Accounting Standards

### Adopted Standards

***Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans.*** In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132(R)." SFAS No. 158 requires balance sheet recognition of the overfunded or underfunded status of pension and other postretirement benefit plans. For pension plans, the liability will be based on the projected benefit obligation. Under SFAS No. 158, any actuarial gains and losses, prior service costs and transition assets or obligations that were not recognized under previous accounting standards must be recognized in accumulated other comprehensive income (AOCI) under common stock equity, net of tax, until they are amortized as a component of net periodic benefit cost. In addition, the measurement date, which is the date when the fair value of plan assets and benefit obligations are measured, is required to be a company's fiscal year end. The measurement date change did not have an impact on our measurement of benefit obligations or the fair value of plan assets because we previously used our fiscal year end as our measurement date.

Effective December 31, 2006, we adopted SFAS No. 158 and recorded balance sheet adjustments to recognize the funded status of our pension and other postretirement plans. These adjustments did not have a material impact on our results of operations, cash flows or our ability to meet our financial debt covenants. We received regulatory approval from the OPUC for deferred asset recognition of AOCI related to the funded status of certain plans under SFAS No. 71 as these amounts are probable of collection in future rates. As such, we have recognized the unfunded status of our qualified pension plans and our postretirement benefit plan as a deferred regulatory asset, and we will recognize changes in actuarial gains and losses, prior service costs and transition assets or obligations each year as an adjustment to the regulatory deferred asset or liability account as these amounts are recognized as components of net periodic benefit costs each year. See Note 7 for a discussion of pension and other postretirement plans.

***Share Based Payment.*** Effective January 1, 2006, we adopted SFAS No. 123R, "Share Based Payment," using the Modified Prospective Application method without restatement of prior periods. Prior to implementation of SFAS No. 123R, we accounted for stock-based compensation using the intrinsic value method prescribed in Accounting Principles Board (APB) Opinion No. 25, "Accounting for Stock Issued to Employees." SFAS No. 123R requires companies to recognize compensation expense for all equity-based compensation awards issued to employees that are expected to vest. Under this method, we began to amortize compensation cost for the remaining portion of outstanding awards for which the requisite service was not yet rendered at January 1, 2006. Compensation cost for these awards was based on the fair value of the awards at the grant date, which was determined under the intrinsic value method. We determine the fair value of and account for awards that are granted, modified or settled on or after January 1, 2006 in accordance with SFAS No. 123R. The adoption of SFAS No. 123R did not have a material impact on our financial condition, results of operations or cash flows. See Note 4 for a discussion of stock-based compensation.

***Accounting for Changes and Error Corrections.*** Effective January 1, 2006, we adopted SFAS No. 154, "Accounting for Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3," which provides guidance on the accounting for and reporting of accounting changes and error corrections. The statement requires retrospective application to prior periods' financial statements of changes in accounting principles, unless it is impracticable to determine the period-specific effects or the cumulative effect of the change. The guidance provided in APB Opinion No. 20 for reporting the correction of an error in previously issued financial statements remains unchanged and requires the restatement of previously issued financial statements. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005. The adoption of SFAS No. 154 did not have an impact upon our financial condition, results of operations or cash flows.

***Inventory Costs.*** Effective January 1, 2006, we adopted SFAS No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4," which amends the guidance on inventory pricing to require that abnormal amounts of idle facility expense, freight, handling costs and wasted material be charged to current period expense rather than capitalized as inventory costs. The adoption of SFAS No. 151 did not have a material impact on our financial condition, results of operations or cash flows.

***Purchases and Sales of Inventory with the Same Counterparty.*** Effective April 1, 2006, we adopted FASB Emerging Issues Task Force (EITF) Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty." EITF 04-13 requires that two or more legally separate exchange transactions with the same counterparty be combined and considered a single arrangement for purposes of applying APB Opinion No. 29, "Accounting for Nonmonetary Transactions," when the transactions are entered into in contemplation of one another. EITF 04-13 was effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006. Adoption of this standard did not have a material impact on our financial condition, results of operations or cash flows.

***Variable Interest Entities.*** In April 2006, the FASB issued a staff position (FSP) interpreting variable interest entities (VIE) under FASB Interpretation No. (FIN) 46(R)-6, "Determining the Variability to be Considered in Applying FIN 46(R)." This FSP emphasizes that preparers should use a "by design" approach in determining whether an interest is variable. A "by design" approach includes evaluating whether an interest is variable based on a thorough understanding of the design of the potential VIE, including the nature of the risks that the potential VIE was designed to create and pass along to interest holders in the entity. Consolidation of a VIE by the primary beneficiary is required if it is determined that the VIE does not effectively disperse risks among the parties involved. FSP No. FIN 46(R)-6 must be applied prospectively to all entities with which the company first becomes involved and to all entities previously required to be analyzed under FIN 46(R) when a reconsideration event has occurred effective on or after July 1, 2006. Implementation of FSP No. FIN 46(R)-6 did not have a material impact on our financial condition, results of operations or cash flows.

Recent Accounting Pronouncements

***Accounting for Certain Hybrid Instruments.*** In February 2006, the FASB issued SFAS No. 155, "Accounting for Certain Hybrid Instruments," which amends SFAS Nos. 133 "Accounting for Derivative Instruments and Hedging Activities," and 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities-a replacement of FASB Statement No. 125." SFAS No. 155 allows financial instruments that have embedded derivatives to be accounted for as a whole if the holder elects to account for the whole instrument on a fair value basis. The statement is effective for all financial instruments acquired or issued after January 1, 2007. We are evaluating the effect of the adoption and implementation of SFAS No. 155, which is not expected to have a material impact on our financial condition, results of operations or cash flows.

***Accounting for Uncertainty in Income Taxes.*** In July 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes—an Interpretation of FASB Statement No. 109," which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return.

FIN 48 is effective as of the beginning of the first annual period after December 15, 2006, or January 1, 2007. It replaces the "probable" and "reasonable estimate" standards of SFAS No. 5 with a two-step approach for determining the amount of tax benefits (thus treating "loss contingencies" and "gain contingencies" consistently) to be recorded in a company's financial statements. Management is required to evaluate all tax positions taken for each jurisdiction and determine the likelihood of the positions being sustained. If management is highly confident that a tax position will be sustained and there is a greater than 50 percent likelihood that the full amount of the tax position will be ultimately realized, a company would recognize the full benefit associated with the tax position.

New disclosures under FIN 48 will primarily consist of:

- A policy on classification of interest and penalties (either as components of operating income or components of the income tax provision);
- A tabular reconciliation of the total amounts of unrecognized tax benefits at the beginning and end of the period;
- The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate; and,
- A description of tax years that remain subject to examination by major tax jurisdictions.

Adoption of FIN 48 will require us to identify and evaluate all material tax positions taken in previously filed and currently open tax returns as well as tax positions expected to be taken in future returns. Each tax position will need to be examined to determine whether the more likely than not recognition standard has been met, and if so, to compute the amount of the tax benefit to be recognized under FIN 48. Based upon a preliminary assessment of the application of FIN 48, the adoption of FIN 48 is not expected to have a material effect on our financial condition, results of operations or cash flows. See Note 8.

***Fair Value Measurements.*** In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which provides a common definition for the measurement of fair value for use in applying GAAP and in preparing financial statement disclosures. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are evaluating the effect of the adoption and implementation of SFAS No. 157, which is not expected to have a material impact on our financial condition, results of operations or cash flows.

Plant and Property and Accrued Asset Removal Costs

Plant and property is stated at cost, including capitalized labor, materials and overhead (see Note 9). The cost of constructing utility plant and gas storage assets includes an allowance for funds used during construction, which represents the net financing cost during the period of funds used for construction purposes (see "Allowance for Funds Used During Construction," below).

Our provision for depreciation of utility property is computed under the straight-line, age-life method in accordance with independent engineering studies and as approved by regulatory authorities. The weighted average depreciation rate for utility plant in service was approximately 3.4 percent for the each of the years ended December 31, 2006, 2005 and 2004, reflecting the approximate economic life of the property.

In accordance with long-standing industry practice, we accrue for future asset removal costs on many long-lived assets through a charge to depreciation expense allowed in rates and accumulate such amounts in regulatory liabilities. At the time removal costs are incurred, accumulated depreciation is charged with the costs of removal and the book cost of the asset. Our estimate of accumulated removal costs is based on rates using our most recent depreciation study. No gain or loss is recognized upon normal retirement. In the rate setting process, the accrued asset removal costs are treated as a reduction to the net rate base.

Allowance for Funds Used During Construction

Certain additions to utility plant include an allowance for funds used during construction, which represents the net cost of borrowed or other funds used during construction and is calculated using actual current interest rates. If borrowings are less than the total costs of construction work in progress, then a composite rate of interest on all debt, shown as a reduction to interest charges, and a return on equity funds, shown as other income, is used to compute the allowance. While cash is not realized currently from allowance for funds used during construction, it is realized in future years through increased revenues from rate recovery resulting from higher rate base and higher depreciation expense. Our composite allowance for funds used during construction rates were 4.7 percent in 2006, 3.1 percent in 2005 and 3.0 percent in 2004.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand and highly liquid temporary investments with original maturity dates of three months or less. At December 31, 2006 and 2005, book overdrafts of $3.7 million and $4.1 million, respectively, were included within accounts payable.

Revenue Recognition and Accrued Unbilled Revenues

Utility revenues, derived primarily from the sale and transportation of gas, are recognized when the gas is delivered to and received by the customer. Revenues include accruals for gas delivered but not yet billed to customers based on estimates of gas deliveries from meter reading dates to month end (accrued unbilled revenues). Accrued unbilled revenues are dependent upon a number of factors that require management's judgment, including total gas receipts and deliveries, customer use and weather. Accrued unbilled revenues are reversed the following month when actual billings occur. Our accrued unbilled revenues at December 31, 2006 and 2005 were $87.5 million and $81.5 million, respectively.

Non-utility revenues, derived primarily from gas storage services, are recognized upon delivery of the service to customers. Revenues from optimization of excess storage and transportation capacity include amounts that are recognized ratably over the life of the contract for guaranteed amounts, or as earned for amounts above the guaranteed amount based on the terms of our contract with the independent energy marketing company which optimizes the value of our assets primarily through the use of commodity transactions and capacity release transactions (see Note 2).

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable consist primarily of amounts due for gas sales and transportation services to core (residential, commercial and industrial firm) customers, plus amounts due for gas storage and other miscellaneous receivables. With respect to these trade receivables and accrued unbilled revenues, we establish an allowance for uncollectible accounts (allowance) based on the aging of receivables, collection experience of past due accounts on payment plans, and historical trends of write-offs as a percent of revenues. With respect to large individual customer receivables, a specific allowance is established and added to the general allowance when amounts are identified as unlikely to be partially or fully recovered. Inactive accounts are written-off against the allowance after 120 days past due or when deemed to be uncollectible. Differences between our estimated allowance and actual write-offs will occur based on changes in general economic conditions, customer credit issues and the level of natural gas prices. Each quarter the allowance for the uncollectible accounts is adjusted, if necessary, based on the most current information available.

Inventories

Inventories, which consist primarily of natural gas in storage for the utility, are generally stated at the lower of average cost or net realizable value. The regulatory treatment of gas inventories provides for full cost recovery in customer rates, subject to a prudency review, including any differences between the actual purchase cost of gas injected into inventory and the embedded cost of inventory in current rates. All gas that is injected into storage is priced into inventory at the actual purchase cost based on a regulatory dispatch model for our gas purchases. All gas that is withdrawn from inventory is charged to cost of gas during the current period at the weighted average cost of inventory embedded in customer rates, which is established in our annual purchased gas adjustment (PGA) filing. Material and supplies inventories are stated at the lower of average cost or net realizable value.

Derivatives

In accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (collectively referred to as SFAS No. 133), we measure derivatives at fair value and recognize them as either assets or liabilities on the balance sheet. SFAS No. 133 requires that changes in the fair value of a derivative be recognized currently in earnings unless specific hedge accounting criteria are met. SFAS No. 133 provides an exception for contracts intended for normal purchases and normal sales for which physical delivery is probable. In addition, certain derivatives contracts are approved by regulatory authorities for recovery through customer rates. Accordingly, the changes in fair value of these contracts are deferred as regulatory assets or liabilities pursuant to SFAS No. 71. Derivatives contracts entered into for core utility customer requirements after the PGA rate has been set are subject to the PGA incentive sharing mechanism, whereby 67 percent of the changes in fair value are deferred as regulatory assets or liabilities and the remaining 33 percent is recorded to the income statement (see Note 11).

Our Financial Derivatives Policy sets forth the guidelines for using selected financial derivative products to support prudent risk management strategies within designated parameters. Our objective for using derivatives is to decrease the volatility of earnings and cash flows and to prevent speculative risk. The use of derivatives is permitted only after the risk exposures have been identified, are determined to exceed acceptable tolerance levels and are considered to be unavoidable because they are necessary to support normal business activities. We do not enter into derivative instruments for trading purposes and we believe that any increase in market risk created by holding derivatives should be offset by the exposures they modify.

Revenue Taxes

We account for utility revenue-based taxes assessed by governmental entities as a separate cost collected from customers for remittance to those governmental entities. Therefore our revenue taxes are accounted for as a cost of sale and presented separately on the income statement.

Income Tax Expense

NW Natural and its one active wholly-owned subsidiary file consolidated federal and state income tax returns. Current income taxes are allocated based on each entity's respective taxable income or loss and investment tax credits as if each entity filed a separate return. We account for income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes." SFAS No. 109 requires recognition of deferred tax liabilities and assets for the future tax consequences of events that have been included in the consolidated financial statements or tax returns. Under this method, deferred tax liabilities and assets are determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse (see Note 8).

SFAS No. 109 also requires recognition of deferred income tax assets and liabilities for temporary differences where regulators prohibit deferred income tax treatment for ratemaking purposes. We have recorded a deferred tax liability equivalent to $67.1 million and $65.8 million at December 31, 2006 and 2005, respectively, to recognize future taxes payable resulting from transactions that have previously been reflected in the financial statements for these temporary differences. Regulatory assets or liabilities corresponding to such additional deferred income tax assets or liabilities may be recorded to the extent we believe they will be recoverable from or payable to customers through the ratemaking process. Pursuant to SFAS No. 71, a corresponding regulatory asset has been recorded which represents the probable future revenue that will result from inclusion in rates charged to customers of taxes which will be paid in the future. The probable future revenue to be recorded takes into consideration the additional future taxes which will be generated by that revenue. Amounts applicable to income taxes due from customers primarily represent differences between the book and tax basis of net utility plant in service and actual removal costs incurred.

Deferred investment tax credits on utility plant additions and leveraged leases, which reduce income taxes payable, are deferred for financial statement purposes and amortized over the life of the related plant or lease. Investment and energy tax credits generated by the non-regulated subsidiary are amortized over a period of one to five years.

## Other Income and Expense—Net

Other income and expense—net consists of interest income, gain on sale of investments, investment income of Financial Corporation and other miscellaneous income from merchandise sales, rents, leases and other items.

| Thousands | 2006 | 2005 |
|---|---|---|
| Other Income and Expense - Net | | |
| Gains from company-owned life insurance | $2,609 | $ 1,856 |
| Interest income | 363 | 403 |
| Earnings from equity investments of Financial Corporation | 191 | 57 |
| Other non-operating expenses | (852) | (1,393) |
| Net interest on deferred regulatory accounts | (177) | 282 |
| Other Income and Expense - Net | $2,134 | $ 1,205 |

## Earnings Per Share

Basic earnings per share are computed based on the weighted average number of common shares outstanding each year. Diluted earnings per share reflect the potential effects of the conversion of convertible debentures and the exercise of stock options. Diluted earnings per share are calculated as follows:

| Thousands, except per share amounts | 2006 | 2005 | 2004 |
|---|---|---|---|
| Net income | $63,415 | $58,149 | $50,572 |
| Convertible debenture interest less taxes | - | - | 200 |
| Net income - diluted | $63,415 | $58,149 | $50,772 |
| Average common shares outstanding - basic | 27,540 | 27,564 | 27,016 |
| Stock based compensation | 117 | 57 | 40 |
| Convertible debentures | - | - | 227 |
| Average common shares outstanding - diluted | 27,657 | 27,621 | 27,283 |
| Earnings per share of common stock - basic | $ 2.30 | $ 2.11 | $ 1.87 |
| Earnings per share of common stock - diluted | $ 2.29 | $ 2.11 | $ 1.86 |

For the years ended December 31, 2006, 2005 and 2004, 105,600 shares, 6,000 shares and 201,800 shares, respectively, represent the number of stock options which were excluded from the calculation of diluted earnings per share because the effect was antidilutive.

## Stock-Based Compensation

We periodically provide stock-based compensation to employees in the form of stock options and other incentive awards. As required by SFAS No. 123R, we recognize the fair value of all share-based payments as compensation expense in the financial statements. Prior to January 1, 2006, as permitted by SFAS No. 123, we applied APB Opinion No. 25, "Accounting for Stock Issued to Employees," to account for stock-based compensation. Accordingly, we did not recognize compensation expense for the fair value of our stock option grants. We implemented SFAS 123R effective January 1, 2006 by applying the modified prospective transition method. The impact on net income of this new standard, had it been adopted in 2005, is reflected in the pro forma amounts in Note 4. We have recognized and will continue to recognize compensation expense for the fair value of stock awards granted under our Long-Term Incentive Plan (LTIP) and the Non-Employee Directors Stock Compensation Plan (NEDSCP) in the period when the shares are earned (see "New Accounting Standards—Adopted Standards—Share Based Payments," above, and Note 4).

## 2. CONSOLIDATED SUBSIDIARY OPERATIONS AND SEGMENT INFORMATION:

At December 31, 2006, we had one active, direct wholly-owned subsidiary, Financial Corporation.

Our core business segment is the local gas distribution segment, also referred to as the "utility," which involves the distribution and sale of natural gas. Another business segment, "gas storage" (previously referred to as "interstate gas storage") represents natural gas storage services provided to intrastate and interstate customers, and includes asset optimization services under a contract with an independent energy marketing company. The remaining business segment, "other," primarily consists of non-regulated investments in alternative energy projects in California (see "Financial Corporation," below), a Boeing 737-300 aircraft leased to Continental Airlines and low-income housing in Portland, Oregon (see Note 9).

### Gas Storage

The gas storage business segment is primarily made up of underground natural gas storage services that we provide to large intra- and inter-state customers using our owned storage capacity that has been developed in advance of core utility customers' requirements. In Oregon, we retain 80 percent of the income before tax from these services and credit the remaining 20 percent to a deferred regulatory account for sharing with core utility customers. For each of the years ended December 31, 2006, 2005 and 2004, this business segment derived a majority of its revenues from five customers. The largest of these customers is served under a long-term contract.

Results for the gas storage segment include revenues, net of amounts shared with core utility customers, from a contract with an independent energy marketing company that optimizes the use of the our assets primarily through the use of commodity transactions and transportation capacity release transactions. In Oregon, we retain 80 percent of the pre-tax income when the costs of the capacity have not been included in utility rates, or 33 percent of the pre-tax income when the costs have been included in core utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for distribution to core utility customers. We have a similar sharing mechanism in Washington for revenue derived from storage and third party optimization.

### Other

At December 31, 2006, we reclassified to current assets our net investment of $5.3 million in a Boeing 737-300 airplane leased to Continental Airlines. The original lease term expires in September 2007, and we expect to sell the airplane by the end of 2007. Also in 2006, we sold non-utility real estate investments for $1.8 million, which resulted in a gain on sale of $0.5 million.

Financial Corporation has several financial investments, including investments as a limited partner in windpower electric generating projects and low-income housing projects. Financial Corporation's total assets were $2.6 million and $3.3 million at December 31, 2006 and 2005, respectively. On January 31, 2005, Financial Corporation sold its limited partnership interests in three solar electric generating systems for approximately $3 million.

Segment Information Summary

The following table presents summary financial information about the reportable segments for 2006, 2005 and 2004. Inter-segment transactions are insignificant.

| Thousands | Utility | Gas Storage | Other | Total |
|---|---|---|---|---|
| 2006 | | | | |
| Net operating revenues | $ 327,267 | $12,761 | $ 148 | $ 340,176 |
| Depreciation and amortization | 63,552 | 883 | - | 64,435 |
| Income from operations | 126,366 | 9,870 | 526 | 136,762 |
| Income from financial investments | 2,609 | - | 191 | 2,800 |
| Net income | 56,653 | 5,982 | 780 | 63,415 |
| Total assets at Dec. 31, 2006 | 1,912,021 | 35,970 | 8,865 | 1,956,856 |
| 2005 | | | | |
| Net operating revenues | $ 315,248 | $ 9,609 | $ 136 | $ 324,993 |
| Depreciation and amortization | 60,935 | 710 | - | 61,645 |
| Income (loss) from operations | 118,794 | 8,158 | (5) | 126,947 |
| Income from financial investments | 1,856 | - | 57 | 1,913 |
| Net income | 52,759 | 4,557 | 833 | 58,149 |
| Total assets at Dec. 31, 2005 | 1,994,868 | 34,574 | 12,862 | 2,042,304 |
| 2004 | | | | |
| Net operating revenues | $ 284,904 | $ 6,423 | $ 168 | $ 291,495 |
| Depreciation and amortization | 56,899 | 472 | - | 57,371 |
| Income (loss) from operations | 104,781 | 5,299 | (54) | 110,026 |
| Income from financial investments | 2,855 | - | 181 | 3,036 |
| Net income | 47,090 | 2,880 | 602 | 50,572 |

## 3. CAPITAL STOCK:

Common Stock

At December 31, 2006, we had reserved 244,406 shares of common stock for issuance under the Employee Stock Purchase Plan, 753,934 shares under our Dividend Reinvestment and Direct Stock Purchase Plan and 1,469,000 shares under our Restated Stock Option Plan (see Note 4).

In connection with the restatement of our Restated Articles of Incorporation, effective May 31, 2006, the par value of our common stock was eliminated. As a result, at December 31, 2006, our "common stock" and "premium on common stock" account balances are reflected on the balance sheet as "common stock."

Expiration of Common Share Purchase Rights

In February 2006, our Board of Directors decided to allow all of the common stock purchase rights (Rights) issued under the Rights Agreement, dated as of February 27, 1996, as amended, to expire in accordance with their terms at the close of business on March 15, 2006.

Stock Repurchase Program

Our publicly announced stock repurchase program allows us to purchase up to 2.6 million shares, or up to $85.0 million in total, of our common stock in the open market or through privately negotiated transactions. A total of 395,500 and 410,200 shares were repurchased under this program in 2006 and 2005, respectively; however, no shares were repurchased in 2004.

Restated Stock Option Plan

There are 2,400,000 shares authorized for option grants under the Restated Stock Option Plan. At December 31, 2006, options on 1,135,000 shares were available for grant and options on 334,000 shares were outstanding.

Convertible Debentures

In August 2005, we redeemed all of our outstanding Convertible Debentures, 7-1/4% Series due 2012, at 100 percent of their principal amount plus accrued interest to the date of redemption. During 2005, debentures with an aggregate principal amount of $4.0 million were converted into shares of common stock on or prior to the redemption date at the rate of 50.25 shares for each $1,000 principal amount of debentures and $0.5 million of debentures were redeemed.

Summary of Changes in Common Stock

The following table shows the changes in the number of shares of our common stock outstanding and the premium on common stock for the years 2006, 2005 and 2004:

| | Shares | Premium on common stock (thousands) |
|---|---|---|
| Balance, Dec. 31, 2003 | 25,938,002 | $ 255,871 |
| Sales to public | 1,290,000 | 35,905 |
| Sales to employees | 27,541 | 605 |
| Sales to stockholders | 157,124 | 4,323 |
| Exercise of stock options - net | 73,649 | 2,285 |
| Conversion of convertible debentures to common | 64,904 | 1,086 |
| Lapse of restricted stock award | (4,500) | (41) |
| Balance, Dec. 31, 2004 | 27,546,720 | $ 300,034 |
| Sales to employees | 30,896 | 741 |
| Sales to stockholders | 113,925 | 3,741 |
| Exercise of stock options - net | 97,068 | 2,241 |
| Conversion of convertible debentures to common | 200,887 | 3,360 |
| Repurchase | (410,200) | (13,646) |
| Balance, Dec. 31, 2005 | 27,579,296 | $ 296,471 |
| Repurchase | (395,500) | (1,461) |
| Sales to employees | 31,397 | - |
| Exercise of stock options - net | 68,548 | 285 |
| Change to no-par common stock | - | (295,295) |
| Balance, Dec. 31, 2006 | 27,283,741 | $ - |

## 4. STOCK-BASED COMPENSATION:

We have the following stock-based compensation plans: the Long-Term Incentive Plan (LTIP); the Restated Stock Option Plan (Restated SOP); the Employee Stock Purchase Plan (ESPP); and the Non-Employee Directors Stock Compensation Plan (NEDSCP). These plans are designed to promote stock ownership in NW Natural by employees and officers and, in the case of the NEDSCP, by non-employee directors.

***Long-Term Incentive Plan***. The LTIP is intended to provide a flexible, competitive compensation program for eligible officers and key employees. An aggregate of 500,000 shares of common stock was authorized for grants under the LTIP as stock bonus, restricted stock or performance-based stock awards. Shares awarded under the LTIP are purchased on the open market.

At December 31, 2006, 375,060 shares of common stock were available for award under the LTIP, assuming that outstanding performance based grants are awarded at the target level. The LTIP stock awards are compensatory awards for which compensation expense is recognized based on the market value of performance shares earned, or a pro rata amortization over the vesting period for the outstanding restricted stock awards.

*Performance-based Stock Awards.* Since the LTIP's inception in 2001 through December 31, 2006, performance-based stock awards have been granted annually based on three-year performance periods. At December 31, 2006, certain performance-based stock award measures had been achieved for the 2004-06 award period. Accordingly, participants will receive 40,446 shares of common stock and a dividend equivalent cash payment equal to the number of shares of common stock received on the award payout multiplied by the aggregate cash dividends paid per share during the performance period. For the 12 months ended December 31, 2006, we accrued and expensed $0.9 million related to the 2004-06 performance-based stock award. At December 31, 2006, on a cumulative basis, $1.7 million has been accrued for the 2004-06 performance period.

At December 31, 2006, the aggregate number of performance-based shares granted and outstanding at the threshold, target and maximum levels were as follows:

| | | Number of Performance Share Awards | | |
|---|---|---|---|---|
| Year Awarded | Performance Period | Threshold | Target | Maximum |
| 2005 | 2005-07 | 6,333 | 33,332 | 66,664 |
| 2006 | 2006-08 | 7,536 | 39,662 | 79,324 |
| | Total | 13,869 | 72,994 | 145,988 |

The threshold level estimates future payout assuming the minimum award payable other than no payout for each component of the formula in the Long-Term Incentive Plan. For each of these performance periods, awards will be based on total shareholder return relative to a peer group of gas distribution companies over the three-year performance period and on performance results achieved relative to specific core and non-core strategies. Compensation expense is recognized in accordance with SFAS No. 123R, based on performance levels achieved and an estimated fair value using a Black-Scholes or binomial model. The weighted-average grant date fair value of unvested shares at December 31, 2006 and 2005 was $30.65 and $42.86, respectively. The weighted-average grant date fair value of shares vested during the year was $40.15 and granted during the year was $18.63. For the 12 months ended December 31, 2006, the amount accrued and expensed as compensation under these LTIP grants was $1.0 million. At December 31, 2006, on a cumulative basis, $1.5 million has been accrued for the 2005-07 and 2006-08 performance periods.

*Restricted Stock Awards.* Restricted stock awards also have been granted under the LTIP. A restricted stock award was granted in 2004 consisting of 5,000 shares that will vest ratably over the period 2005-09, and a restricted stock award was granted in 2006 consisting of 6,500 shares that will vest ratably over the period 2007-09. A total of 2,000 restricted stock award shares were vested at December 31, 2006. Compensation expense is recognized ratably over the vesting period.

***Restated Stock Option Plan.*** The Restated SOP authorizes an aggregate of 2,400,000 shares of common stock for issuance as incentive or non-statutory stock options. These options may be granted only to officers and key employees designated by a committee of our Board of Directors. All options are granted at an option price not less than the market value at the date of grant and may be exercised for a period not exceeding 10 years from the date of grant. Option holders may exchange shares they have owned for at least six months, at the current market price, to purchase shares at the option price. We use original issue shares upon exercise of options under the plan (see Note 3.)

***Employee Stock Purchase Plan.*** The ESPP allows employees to purchase common stock at 85 percent of the closing price on the trading day immediately preceding the initial offering date, which is set annually. Each eligible employee may purchase up to $24,000 worth of stock through payroll deductions over a six- to 12-month period. We use original issue shares upon exercise of options under the plan (see Note 3.)

In accordance with APB Opinion No. 25, no compensation expense was recognized for options granted under the Restated SOP or shares issued under the ESPP during 2005 or earlier years (see Note 1, "New Accounting Standards—Adopted Standards—Share Based Payment"). If compensation expense for awards under these two plans had been determined based on fair value at the grant dates using the method prescribed by SFAS No. 123R, net income and earnings per share would have been reduced to the pro forma amounts shown below:

| Pro Forma Effect of Stock-Based Options and ESPP:<br>Thousands, except per share amounts | 2005 | 2004 |
|---|---|---|
| Net income as reported | $58,149 | $50,572 |
| Add: Stock based compensation expense included in reported net income - net of related tax effects | 613 | 96 |
| Deduct: Pro forma stock-based compensation expense determined under the fair value based method - net of related tax effects | (940) | (519) |
| Pro forma earnings applicable to common stock - basic | 57,822 | 50,149 |
| Debenture interest less taxes | - | 200 |
| Pro forma earnings applicable to common stock—diluted | $57,822 | $50,349 |
| Basic earnings per share | | |
| As reported | $ 2.11 | $ 1.87 |
| Pro forma | $ 2.10 | $ 1.86 |
| Diluted earnings per share | | |
| As reported | $ 2.11 | $ 1.86 |
| Pro forma | $ 2.09 | $ 1.85 |

The fair value of each stock option is estimated on the grant date using the Black-Scholes option pricing model with the following weighted average assumptions:

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Risk-free interest rate | 4.5% | 4.2% | 3.6% |
| Expected Life (in years) | 6.2 | 7.0 | 7.0 |
| Expected market price volatility factor | 22.8% | 24.6% | 25.2% |
| Expected dividend yield | 4.0% | 3.6% | 4.1% |
| Present value of options granted | $26.00 | $27.87 | $24.55 |

The simplified formula for "plain vanilla" options was utilized to determine the expected life as defined and permitted by Staff Accounting Bulletin No. 107. The risk-free interest rate was based on the implied yield currently available on U.S. Treasury zero-coupon issues with a life equal to the expected life of the options. Historical data was employed in order to estimate the volatility factor, measured on a daily basis, for a period equal to the duration of the expected life of the option awards. The dividend yield was based on management's current estimate for dividend payout at the time of grant. A forfeiture rate of 3 percent was applied to the calculation of compensation expense. We expense the total cost of stock option awards granted to retirement eligible employees at the date of grant in accordance with SFAS No. 123R and the retirement provisions of our plan.

Information regarding the Restated SOP's activity for the three years ended December 31, 2006 is summarized as follows:

| | | Price per Share | |
|---|---|---|---|
| | Option Shares | Range | Weighted-Average Exercise Price |
| Balance outstanding, Dec. 31, 2003 | 322,044 | $20.25 - 27.875 | $25.35 |
| Granted | 202,800 | 31.34 - 32.02 | 31.40 |
| Exercised | (92,074) | 20.25 - 27.875 | 24.39 |
| Forfeited | (1,300) | 26.30 - 31.34 | 30.18 |
| Balance outstanding, Dec. 31, 2004 | 431,470 | 20.25 - 32.02 | 28.38 |
| Granted | 9,000 | 34.95 - 38.30 | 37.18 |
| Exercised | (121,170) | 20.25 - 31.34 | 26.59 |
| Forfeited | (10,800) | 27.60 - 31.34 | 30.79 |
| Balance outstanding, Dec. 31, 2005 | 308,500 | 20.25 - 38.30 | 29.26 |
| Granted | 97,800 | 34.29 | 34.29 |
| Exercised | (69,300) | 20.25 - 31.34 | 27.15 |
| Forfeited | (3,000) | 31.34 - 34.29 | 32.52 |
| Balance outstanding, Dec. 31, 2006 | 334,000 | $20.25 - 38.30 | $31.14 |
| Shares available for grant Dec. 31, 2004 | 1,228,000 | | |
| Shares available for grant Dec. 31, 2005 | 1,229,800 | | |
| Shares available for grant Dec. 31, 2006 | 1,135,000 | | |

The weighted average remaining life of outstanding stock options at December 31, 2006 was 7.10 years.

The weighted-average grant-date fair value of equity awards granted during 2005 and 2006 was $7.85 and $6.29, respectively. At December 31, 2006, a total of 179,700 options were exercisable.

During the year ended December 31, 2006, pre-tax compensation expense amounted to $0.6 million relating to options granted under the Restated SOP. This expense was recognized in operations and maintenance expense under the fair value method in accordance with SFAS No. 123R. In addition, $0.2 million of pre-tax compensation expense related to the ESPP was recognized for the year. As of December 31, 2006, there was $0.4 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2009.

In the year ended December 31, 2006, 69,300 option shares were exercised with a total intrinsic value of $0.8 million. Cash of $2.2 million was received for these exercises and a $0.3 million related tax benefit was realized. The total intrinsic value of options exercised in the years ended December 31, 2005 and 2004 was $1.2 million and $0.7 million, respectively, and the total fair value of options that vested was $0.4 million in both 2006 and 2005 and $0.6 million in 2004.

The following table summarizes additional information about stock options outstanding and exercisable at December 31, 2006:

| | Outstanding | | Exercisable | | | |
|---|---|---|---|---|---|---|
| Range of Exercise Prices | Stock Options | (In millions) Aggregate Intrinsic Value | Stock Options | (In millions) Aggregate Intrinsic Value | Weighted-Average Exercise Price | Weighted-Average Remaining Life in Years |
| $20.25 - 38.30 | 334,000 | $3.8 | 179,700 | $2.4 | $29.16 | 5.9 |

In accordance with SFAS No. 123R, we capitalize a portion of the expense recognized in relation to stock based compensation. The following table summarizes the effects of stock based compensation resulting from the application of SFAS No. 123R granted under our LTIP, SOP and ESPP:

| Thousands, except per share amounts | 2006 |
|---|---|
| Operations and maintenance | $ 2,304 |
| Stock-based compensation effect on income before taxes | 2,304 |
| Income taxes | (898) |
| Net stock-based compensation effect on net income | $ 1,406 |
| Effect on basic earnings per share | $ 0.05 |
| Effect on diluted earnings per share | $ 0.05 |
| Effect on cash flow from operations | $(1,136) |
| Effect on cash flow from financing activities | $ 1,280 |

***Non-Employee Directors Stock Compensation Plan.*** In February 2004, the NEDSCP was amended to permit non-employee directors to receive stock awards either in cash or in our stock. As a result of modifications to the directors' compensation arrangements, the NEDSCP was further amended in September 2004 to eliminate any further awards, either in cash or stock, on and after January 1, 2005.

Prior to the latter amendment to the NEDSCP, if non-employee directors elected to receive their awards in stock, approximately $100,000 worth of common stock was awarded upon joining the Board. These stock awards were subject to vesting and to restrictions on sale and transferability. The shares vested in monthly installments over the five calendar years following the award. On January 1 of each year following the initial award, non-employee directors who elected to receive their awards in stock were awarded an additional $20,000 worth of restricted stock, which vested in monthly installments in the fifth year following the award (after the previous award had fully vested). We hold the certificates for the restricted shares until the non-employee director ceases to be a director. Participants receive all dividends and have full voting rights on both vested and unvested shares. All awards vest immediately upon the death of a director or upon a change in control of the Company. Any unvested shares are considered to be unearned compensation, and thus are forfeited if the recipient ceases to be a director. The shares were purchased in the open market by us at the time of the award. During 2006, 7,848 shares vested under the plan and no forfeitures occurred. At December 31, 2006, 11,071 shares remain unvested, all of which are scheduled to vest by December 31, 2008. The weighted-average grant-date fair value of unvested shares at December 31, 2006 and 2005 was $28.92 and $29.02, respectively.

Changes in unearned stock compensation in 2006 resulted from purchases of restricted stock related to the restricted stock grant under the LTIP for $0.2 million, offset by restricted stock amortizations of $0.3 million. In 2005, the change in unearned stock compensation consisted of $0.2 million of restricted stock amortizations.

Under a separate plan, prior to January 1, 2005, non-employee directors could elect to invest their cash fees and retainers for board service in shares of common stock. Under a new deferral plan effective January 1, 2005, such fees and retainers will be deferred to a cash account. Cash account balances may be transferred to and invested in a stock account at the election of the director up to four times per year.

## 5. LONG-TERM DEBT:

The issuance of first mortgage debt, including secured medium-term notes, under the Mortgage and Deed of Trust (Mortgage), is limited by property additions, adjusted net earnings and other provisions of the Mortgage. The Mortgage constitutes a first mortgage lien on substantially all of our utility property.

The maturities on the long-term debt outstanding, for each of the 12-month periods through December 31, 2011 amount to: $29.5 million in 2007; $5 million in 2008; none in 2009; $35 million in 2010; and $10 million in 2011. Holders of certain long-term debt have put options that, if exercised, would accelerate the maturities by $20 million in each of 2007, 2008 and 2009.

In December 2006, we issued and sold $25 million of 5.15% Series B secured Medium Term Notes (MTNs) due 2016. Proceeds from this sale were used, in part, to repay short-term debt and fund our ongoing utility construction program.

In June 2005, we issued and sold $50 million in principal amount of secured MTNs, consisting of $40 million of the 4.70% Series B due 2015 and $10 million of the 5.25% Series B due 2035. Proceeds from these sales were used, in part, to redeem $15 million of maturing MTNs in July 2005, and the balance was applied to our ongoing utility construction program and the repayment of short-term debt.

In July 2005, we redeemed three series of maturing MTNs aggregating $15 million in principal amount. The series redeemed were the 6.34% Series B, the 6.38% Series B and the 6.45% Series B, each with a principal balance outstanding of $5 million due in July 2005.

## 6. NOTES PAYABLE AND LINES OF CREDIT:

Our primary source of short-term funds is from the sale of commercial paper notes payable. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas purchases, gas inventories and accounts receivable, short-term debt is used temporarily to fund capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by committed bank lines of credit (see below). At December 31, 2006 and 2005, the amounts and average interest rates of commercial paper debt outstanding were $100.1 million and 5.3 percent and $126.7 million and 4.3 percent, respectively. We have not issued commercial paper in an aggregate amount outstanding in excess of our committed lines of credit.

In September 2005, we entered into an agreement for unsecured lines of credit totaling $200 million with five commercial banks, replacing the existing $150 million credit facilities. The bank lines of credit (bank lines) are available and committed for a term of five years, beginning October 1, 2005 and expiring on September 30, 2010. Our bank lines are used primarily as back-up support for the notes payable under our commercial paper borrowing program. Commercial paper borrowing provides the liquidity to meet our working capital and external financing requirements. Under the terms of these bank lines, we pay upfront fees and annual commitment fees but are not required to maintain compensating bank balances. The interest rates on outstanding loans, if any, under these bank lines are based on then-current market interest rates. All principal and unpaid interest under the bank lines is due and payable on September 30, 2010.

The bank lines require that we maintain credit ratings with Standard & Poor's and Moody's Investors Service and notify the banks of any change in our senior unsecured debt ratings by such rating agencies. A change in our credit rating is not an event of default, nor is the maintenance of a specific minimum level of credit rating a condition of drawing upon the bank lines. However, interest rates on any loans outstanding under these bank lines are tied to credit ratings, which would increase or decrease the cost of any loans under the bank lines when ratings are changed.

The bank lines also require us to maintain an indebtedness to total capitalization ratio of 65 percent or less. Failure to comply with this covenant would entitle the banks to terminate their lending commitments and to accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2006, with an indebtedness to total capitalization ratio of 51.9 percent.

## 7. PENSION AND OTHER POSTRETIREMENT BENEFITS:

We maintain two qualified non-contributory defined benefit pension plans covering all regular employees with more than one year of service, several non-qualified supplemental pension plans for eligible executive officers and certain key employees and other postretirement benefit plans for employees. Only the two qualified defined benefit pension plans have plan assets, which are held in a qualified trust to fund retirement benefits. Effective January 1, 2007, the Retirement Plan for Non-Bargaining Unit Employees and the Welfare Benefits Plan for Non-Bargaining Unit Employees was closed to anyone hired or rehired after December 31, 2006. Instead, newly hired or rehired non-bargaining unit employees will be provided an enhanced Retirement K Savings Plan (401k) benefit. Benefits provided to bargaining unit employees are not affected by these changes.

The following table provides a reconciliation of the changes in benefit obligations and fair value of plan assets, as applicable, for the pension and other postretirement benefit plans over the three-year period ended December 31, 2006, and a summary of the funded status and amounts recognized in the consolidated balance sheets using measurement dates of December 31, 2006, 2005 and 2004:

| | Postretirement Benefits | | | | | |
|---|---|---|---|---|---|---|
| | Pension Benefits | | | Other Benefits | | |
| Thousands | 2006 | 2005 | 2004 | 2006 | 2005 | 2004 |
| Reconciliation of change in benefit obligation: | | | | | | |
| Obligation at January 1 | $267,854 | $222,948 | $205,352 | $ 20,398 | $ 22,729 | $ 23,379 |
| Service cost | 7,745 | 6,322 | 5,428 | 555 | 767 | 457 |
| Interest cost | 14,901 | 13,203 | 12,690 | 1,184 | 1,248 | 1,232 |
| Special termination benefits | - | - | 237 | - | - | - |
| Expected benefits paid | (13,183) | (12,866) | (10,682) | (1,015) | (1,173) | (1,040) |
| Plan amendments | - | 1,408 | - | 15 | 2,384 | - |
| Change in assumptions | (9,208) | 31,642 | - | 133 | 2,215 | - |
| Net actuarial (gain) or loss | 1,301 | 5,197 | 9,923 | 1,166 | (7,772) | (1,299) |
| Obligation at December 31 | $269,410 | $267,854 | $222,948 | $ 22,436 | $ 20,398 | $ 22,729 |
| Reconciliation of change in plan assets: | | | | | | |
| Fair value of plan assets at January 1 | $218,555 | $186,787 | $168,324 | $ - | $ - | $ - |
| Actual return on plan assets | 30,088 | 12,558 | 19,835 | - | - | - |
| Employer contributions | 1,058 | 32,076 | 9,310 | 1,015 | 1,173 | 1,040 |
| Benefits paid | (13,183) | (12,866) | (10,682) | (1,015) | (1,173) | (1,040) |
| Fair value of plan assets at December 31 | $236,518 | $218,555 | $186,787 | $ - | $ - | $ - |
| Funded status: | | | | | | |
| Funded status at December 31 | $ (32,892) | $ (49,299) | $ (36,162) | $(22,436) | $(20,397) | $(22,728) |
| Unrecognized transition obligation | - | - | - | 2,469 | 2,880 | 3,292 |
| Unrecognized prior-service cost | 5,512 | 6,492 | 5,146 | 2,063 | 2,243 | - |
| Unrecognized net actuarial loss | 45,862 | 69,766 | 33,897 | 2,288 | 988 | 6,717 |
| Net amount recognized | $ 18,482 | $ 26,959 | $ 2,881 | $(15,616) | $(14,286) | $(12,719) |

In September 2006, the FASB issued SFAS No. 158 (see Note 1, "New Accounting Standards—Adopted Standards"). SFAS No. 158 requires balance sheet recognition of the overfunded or underfunded status of pension and other postretirement benefit plans. For pension plans, the liability is based on the projected benefit obligation. Under SFAS No. 158, any actuarial gains and losses, prior service costs and transition assets or obligations that were not recognized under previous accounting standards must be recognized in AOCI under common stock equity, net of tax, until they are amortized as a component of net periodic benefit cost. We consider the recognition of the underfunded status of the qualified defined benefit plans and postretirement benefit plans to be subject to regulatory deferral under SFAS No. 71. The unrecognized net gains and losses, prior service costs and transition obligations relating to our qualified defined benefit pension and postretirement benefit plans were recognized as regulatory assets at December 31, 2006. An estimated $3.5 million consisting of actuarial gains of $1.9 million, prior service costs of $1.2 million and transition obligations of $0.4 million for the qualified plans will be amortized from the regulatory asset to net periodic benefit cost in 2007. The gains and losses, prior service costs and transition obligations related to our non-qualified supplemental pension plans are recognized in AOCI, net of tax, under common stock equity because these expenses are not the basis for regulatory recovery; however, these amounts are not material. In 2007, an estimated $0.2 million consisting of actuarial gains of $0.2 million and negligible prior service costs for the non-qualified plans will be amortized from AOCI to net periodic benefit cost.

The adoption of SFAS No. 158 did not have a material impact on our results of operations, cash flows or our ability to meet our financial debt covenants. The following table provides a summary of the changes in the statement of financial position at December 31, 2006 due to the application of SFAS No. 158:

| Thousands | Before Application of SFAS No. 158 | Adjustments: Adoption of SFAS No. 158 | Adjustments: Regulatory Deferral | After Application of SFAS No. 158 |
|---|---|---|---|---|
| Minimum pension liability [1] | $ 3,173 | $ (3,173) | $ - | $ - |
| Pension benefit liabilities - current | - | 1,134 | - | 1,134 |
| Pension benefit liabilities - non-current | 10,174 | 21,583 | - | 31,757 |
| Postretirement benefit liability - current | - | 1,503 | - | 1,503 |
| Postretirement benefit liability - non-current | 15,616 | 5,317 | - | 20,933 |
| Deferred income taxes and investment tax credits | 210,316 | (21,442) | 21,210 | 210,084 |
| Regulatory asset | - | - | 54,425 | 54,425 |
| Prepaid pension asset | 28,657 | (28,657) | - | - |
| Accumulated other comprehensive income | (1,992) | (33,579) | 33,215 | (2,356) |
| Total assets | 1,931,088 | (28,657) | 54,425 | 1,956,856 |
| Total liabilities | 814,179 | 4,922 | 21,210 | 840,311 |
| Total capitalization | 1,116,909 | (33,579) | 33,215 | 1,116,545 |

[1] The minimum pension liability before the adoption of SFAS No. 158 includes a current year adjustment of $0.1 million, net of tax.

Our qualified defined benefit pension plans had a projected benefit obligation in excess of plan assets at December 31, 2006. The plans' aggregate projected benefit obligations were $255 million, $254 million and $209 million at December 31, 2006, 2005 and 2004, respectively, and the fair value of plan assets was $236.5 million, $218.6 million and $186.8 million, respectively. The projected benefit obligations at December 31, 2006 decreased by $9.3 million, reflecting the increase in the discount rate assumptions and increased by $0.3 million, reflecting retirement and withdrawal rates updated for actual experience. The projected benefit obligations at December 31, 2005 increased $26.6 million from December 31, 2004 due to the use of updated mortality rates and increased $8.1 million due to a decrease in the discount rate. The combination of investment returns and future cash contributions is expected to provide sufficient funds to cover all future benefit obligations of the plans.

The assumed discount rates were determined independently for each pension and other postretirement benefit plan based on the Citigroup Above Median Curve (Citigroup curve) using high quality bonds (rated AA- or higher by Standard & Poors or Aa3 or higher by Moody's Investor Service). The Citigroup curve was applied to match the estimated cash flows to reflect the timing and amount of future benefit payments for these plans.

The expected long-term rate of return on plan assets was developed as a weighted average of the expected earnings for the target asset portfolio. In developing the expected long-term rate of return assumption, consideration was given to the historical performance of each asset class in which the plans' assets are invested and the target asset allocation for plan assets.

Our Investment Policy and Performance Objectives for the qualified pension plan assets held in the Retirement Trust Fund were approved by the retirement committee which is composed of senior management employees. The policy sets forth the guidelines and objectives governing the investment of plan assets. Plan assets are invested for total return with appropriate consideration for liquidity and portfolio risk. All investments are expected to satisfy the requirements of the rule of prudent investments as set forth under the Employee Retirement Income Security Act of 1974. The approved asset classes are cash and short-term investments, fixed income, common stock and convertible securities, absolute and real return strategies, real estate and investments in our common stock. Plan assets may be invested in separately managed accounts or in commingled or mutual funds. Re-balancing will take place periodically as needed, or when significant cash flows occur, in order to maintain the allocation of assets within the stated target ranges. Our expected long-term rate of return is based upon historical index returns by asset class, adjusted by a factor based on our historical return experience. The Retirement Trust Fund is not currently invested in any NW Natural securities.

Our pension plan asset allocation at December 31, 2006 and 2005, and the target allocation and expected long-term rate of return by asset category, are as follows:

| | Percentage of Plan Assets Dec. 31, | | | |
|---|---|---|---|---|
| Asset Category | 2006 | 2005 | Target Allocation | Expected Long-term Rate of Return |
| US Large Cap Equity | 19.2% | 19.8% | 20% | 8.50% |
| US Small/Mid Cap Equity | 13.9% | 14.2% | 15% | 9.50% |
| Non-US Equity | 23.5% | 19.7% | 20% | 8.75% |
| Fixed Income | 15.6% | 19.3% | 15% | 5.50% |
| Real Estate | 7.7% | 6.2% | 8% | 7.75% |
| Absolute Return Strategies | 14.3% | 14.2% | 15% | 9.00% |
| Real Return | 5.8% | 6.6% | 7% | 7.75% |
| Weighted Average | | | | 8.25% |

Our non-qualified supplemental pension plans' benefit obligations were $13.9 million, $13.5 million and $13.6 million at December 31, 2006, 2005 and 2004, respectively. These plans are not subject to regulatory deferral and the changes in actuarial gains and losses, prior service costs and transition assets or obligations for these plans were recognized in AOCI under common stock equity, net of tax, until they are amortized as a component of net periodic benefit cost. Although the plans are unfunded plans with no plan assets due to their nature as non-qualified plans, we indirectly fund our obligations with trust-owned life insurance.

Our plans for providing postretirement benefits other than pensions also are unfunded plans, but are subject to regulatory deferral. The gains and losses, prior service costs and transition assets or obligations for these plans were recognized as a regulatory asset. The accumulated postretirement benefit obligation for those plans was $22.4 million, $20.4 million and $22.7 million at December 31, 2006, 2005 and 2004, respectively.

Net periodic benefit costs consist of service costs, interest costs, the amortization of actuarial gains and losses, the expected returns on plan assets and, in part, on a market-related valuation of assets. The market-related valuation reflects differences between expected returns and actual investment returns, which are recognized over a three-year period from the year in which they occur, thereby reducing year-to-year net periodic benefit cost volatility.

The following tables provide the components of net periodic benefit cost for the qualified and non-qualified pension and other postretirement benefit plans for the years ended December 31, 2006, 2005 and 2004 and the assumptions used in measuring these costs and benefit obligations:

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| Thousands | 2006 | 2005 | 2004 | 2006 | 2005 | 2004 |
| Service cost | $ 7,745 | $ 6,322 | $ 5,428 | $ 556 | $ 767 | $ 457 |
| Interest cost | 14,901 | 13,203 | 12,689 | 1,184 | 1,248 | 1,232 |
| Expected return on plan assets | (17,611) | (14,449) | (13,284) | - | - | - |
| Amortization of transition obligations | - | - | - | 411 | 411 | 411 |
| Amortization of prior service costs | 979 | 1,077 | 1,094 | 195 | 142 | - |
| Amortization of net loss | 3,520 | 2,082 | 1,631 | 1 | 173 | 288 |
| Net periodic benefit cost | $ 9,534 | $ 8,235 | $ 7,558 | $ 2,347 | $ 2,741 | $ 2,388 |
| Assumptions for net periodic benefit cost: | | | | | | |
| Discount rate | 5.75% | 6.00% | 6.25% | 5.75% | 6.00% | 6.25% |
| Rate of increase in compensation | 4.0%-5.0% | 4.0%-5.0% | 4.0%-5.0% | n/a | n/a | n/a |
| Expected long-term rate of return | 8.25% | 8.25% | 8.25% | n/a | n/a | n/a |
| Assumptions for funded status: | | | | | | |
| Discount rate | 6.0%-6.05% | 5.75% | 6.00% | 5.91% | 5.75% | 6.00% |
| Rate of increase in compensation | 4.0%-5.0% | 4.0%-5.0% | 4.0%-5.0% | n/a | n/a | n/a |
| Expected long-term rate of return | 8.25% | 8.25% | 8.25% | n/a | n/a | n/a |

The assumed annual increase in trend rates used in measuring postretirement benefits as of December 31, 2006 were 9 percent for medical and 12 percent for prescription drugs. Medical costs were assumed to decrease gradually each year to a rate of 4.5 percent by 2013, while prescription drug costs were assumed to decrease gradually each year to a rate of 4.5 percent by 2014.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans. A one-percentage point change in assumed health care cost trend rates would have the following effects:

| Thousands | 1% Increase | 1% Decrease |
|---|---|---|
| Effect on total of service and interest cost components of net periodic postretirement health care benefit cost | $ 23 | $ (21) |
| Effect on health care cost component of the accumulated postretirement benefit obligation | $613 | $(628) |

The following table provides information regarding employer contributions and benefit payments for the two qualified pension plans, the non-qualified pension plans and the other postretirement benefit plans for the years ended December 31, 2006 and 2005, and estimated future payments:

| Thousands | Pension Benefits | Other Benefits |
|---|---|---|
| Employer Contributions by Plan Year | | |
| For 2005 | $ 12,497 | $ 1,173 |
| For 2006 | 1,527 | 1,015 |
| For 2007 (estimated) | 1,655 | 1,571 |
| Benefit Payments | | |
| 2004 | $ 10,682 | $ 1,040 |
| 2005 | 12,866 | 1,173 |
| 2006 | 13,183 | 1,015 |
| Estimated Future Payments | | |
| 2007 | $ 13,139 | $ 1,571 |
| 2008 | 13,818 | 1,596 |
| 2009 | 14,513 | 1,626 |
| 2010 | 15,615 | 1,685 |
| 2011 | 16,221 | 1,753 |
| 2012-2016 | 93,212 | 9,002 |

Our Retirement K Savings Plan (RKSP) is a qualified defined contribution plan under Internal Revenue Code Section 401(k). We also have non-qualified deferred compensation plans for eligible officers and senior managers. These plans are designed to enhance the retirement program of employees and to assist them in strengthening their financial security by providing an incentive to save and invest regularly. Our matching contributions to these plans totaled $1.8 million in 2006 and $1.7 million in both 2005 and 2004. The RKSP includes an Employee Stock Ownership Plan.

In addition, in 2005 we began making contributions on behalf of each union employee to the Western States Office and Professional Employees Pension Fund, a multi-employer plan. In both 2006 and 2005, these contributions amounted to $0.5 million.

## 8. INCOME TAXES:

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

| Thousands, except percentages | 2006 | 2005 | 2004 |
|---|---|---|---|
| Income taxes at federal statutory rate | $ 34,877 | $31,804 | $ 26,986 |
| Increase (decrease): | | | |
| Current state income tax, net of federal tax benefit | 3,655 | 2,913 | 2,554 |
| Federal income tax credits | - | (210) | (210) |
| Amortization of investment and energy tax credits | (994) | (956) | (920) |
| Differences required to be flowed-through by regulatory commissions | (704) | (704) | (704) |
| Gains on Company and trust-owned life insurance | (913) | (650) | (955) |
| Other - net | 155 | 187 | 172 |
| Reversal of amounts provided in prior years | 158 | 336 | (392) |
| Total provision for income taxes | $ 36,234 | $32,720 | $ 26,531 |
| Federal statutory tax rate | 35.0% | 35.0% | 35.0% |
| Increase (decrease): | | | |
| Current state income tax, net of federal tax benefit | 3.7% | 3.2% | 3.3% |
| Federal income tax credits | 0.0% | -0.2% | -0.3% |
| Amortization of investment and energy tax credits | -1.0% | -1.1% | -1.2% |
| Differences required to be flowed-through by regulatory commissions | -0.7% | -0.8% | -0.9% |
| Gains on Company and trust-owned life insurance | -0.9% | -0.7% | -1.2% |
| Other - net | 0.2% | 0.2% | 0.2% |
| Reversal of amounts provided in prior years | 0.1% | 0.4% | -0.5% |
| Effective tax rate | 36.4% | 36.0% | 34.4% |

The provision for income taxes consists of the following:

| Thousands | 2006 | 2005 | 2004 |
|---|---|---|---|
| Current tax expense (benefit) | $ 52,621 | $23,034 | $(10,718) |
| Deferred tax expense (benefit) | (15,393) | 10,642 | 38,170 |
| Deferred investment and energy tax credits | (994) | (956) | (920) |
| Total provision for income taxes | $ 36,234 | $32,720 | $ 26,531 |
| Total income taxes paid | $ 31,270 | $28,479 | $ 2,500 |

The amount of income taxes paid in 2006 and 2005 increased significantly as compared to the total income taxes paid in 2004. This was primarily due to the effects of the accelerated bonus depreciation provisions of the Job Creation and Worker Assistance Act of 2002 (Assistance Act) and of the Jobs and Growth Tax Relief Reconciliation Act of 2003 (Reconciliation Act). The Assistance Act provided for an additional depreciation deduction equal to 30 percent of an asset's adjusted basis. The Reconciliation Act increased this first-year additional depreciation deduction to 50 percent of an asset's adjusted basis. The accelerated depreciation provisions provided by the Acts expired December 31, 2004. We realized current tax benefits totaling an estimated $57 million during the effective period, based on plant investments made between September 11, 2001 and December 31, 2004. The accelerated depreciation provisions in 2004 were the primary factors resulting in net operating losses (NOL) for tax purposes.

The following table summarizes the total provision for income taxes for the regulated utility and other non-regulated business segments for the three years ended December 31:

| Thousands | 2006 | 2005 | 2004 |
|---|---|---|---|
| Regulated utility: | | | |
| Federal | | | |
| Current | $ 40,979 | $17,848 | $(10,794) |
| Deferred | (12,472) | 8,690 | 35,213 |
| Deferred investment and energy tax credits | (756) | (784) | (800) |
| | 27,750 | 25,755 | 23,618 |
| State | | | |
| Current | 7,490 | 1,650 | (1,094) |
| Deferred | (2,338) | 2,855 | 5,027 |
| | 5,152 | 4,504 | 3,933 |
| Total charged to regulated utility | 32,902 | 30,259 | 27,551 |
| Non-regulated business segments: | | | |
| Federal | | | |
| Current | 3,807 | 3,581 | 1,187 |
| Deferred | (714) | (1,189) | (1,610) |
| Deferred investment and energy tax credits | (238) | (172) | (120) |
| | 2,855 | 2,220 | (543) |
| State | | | |
| Current | 346 | (44) | (17) |
| Deferred | 131 | 285 | (460) |
| | 477 | 241 | (478) |
| Total charged to non-regulated business segments | 3,331 | 2,461 | (1,020) |
| Total provision for income taxes | $ 36,234 | $32,720 | $ 26,531 |

The following table summarizes the tax effect of significant items comprising our deferred income tax accounts for the two years ended December 31:

| Thousands | 2006 | 2005 |
|---|---|---|
| Deferred tax liabilities (assets) | | |
| Utility plant and equipment | $150,648 | $146,681 |
| Utility regulatory balances | - | 3,045 |
| Utility other deferred tax differences | - | 1,769 |
| Non-regulated deferred tax differences | 3,893 | 6,121 |
| Deferred tax liabilities | 154,540 | 157,616 |
| Utility regulatory balances | (10,039) | - |
| Utility other deferred tax differences | (4,053) | - |
| Deferred tax assets | (14,092) | - |
| | 140,448 | 157,616 |
| Regulatory income tax assets | 67,141 | 65,843 |
| Minimum pension liability | (1,413) | (1,128) |
| Deferred income taxes | 206,177 | 222,331 |
| Deferred investment tax credits | 3,907 | 5,069 |
| Deferred income taxes and investment tax credits | $210,084 | $227,400 |

We have determined that the utility is more likely than not to realize all recorded deferred tax assets as of December 31, 2006.

The following is a reconciliation of the change in our deferred tax balance for the year ended December 31:

| Thousands | 2006 |
| --- | --- |
| Deferred tax expense (benefit), above | $(15,393) |
| Increase in differences required to be flowed-through | 1,298 |
| Decrease in minimum pension liability included in OCI | (285) |
| Decrease in deferred taxes associated with asset held for sale | (1,942) |
| Decrease in deferred investment tax credits | (994) |
| Change in deferred income tax accounts | $(17,316) |

We calculate our deferred tax assets and liabilities under SFAS No. 109, which requires recording deferred tax balances, at the currently enacted tax rate, on assets and liabilities that are reported differently for income tax purposes than for financial reporting purposes. Deferred tax provisions are not recorded in the income statement for certain temporary differences where regulators require that we flow through deferred income tax benefits or expenses in the ratemaking process of the regulated utility.

A deferred income tax charge associated with accruals of minimum pension liability was included in AOCI.

The Internal Revenue Service (IRS) completed its audit of our consolidated income tax returns for the years 2002-2004 in the second quarter of 2006. The focus of the examination was the $35.8 million NOL generated in 2004 and carried back to 2002. This loss was primarily due to the deductions claimed for a pension contribution and accelerated depreciation provided by both the Assistance Act and the Reconciliation Act discussed above. A federal refund of $8.3 million was received in October 2005. In conjunction with recording the refund, we recorded additional federal and state income tax credits of $4.2 million. In addition to the NOL, the IRS examined income tax positions taken with respect to various other ordinary business transactions. We reached agreement with the IRS for certain income tax positions such that a notice of proposed adjustment was issued. As a result of this agreement, we recorded an immaterial income tax benefit of $0.1 million.

## 9. PROPERTY AND INVESTMENTS:

The following table sets forth the major classifications of our utility plant and accumulated depreciation at December 31:

| Thousands, except percentages | 2006 Amount | 2006 Weighted Average Depreciation Rate | 2005 Amount | 2005 Weighted Average Depreciation Rate |
|---|---|---|---|---|
| Transmission and distribution | $1,657,466 | 3.3% | $1,575,545 | 3.2% |
| Utility storage | 110,721 | 2.6% | 109,908 | 2.6% |
| General | 92,946 | 2.6% | 90,780 | 3.1% |
| Intangible and other | 68,088 | 8.6% | 66,354 | 8.4% |
| Gas stored long-term | 12,850 | 0.0% | 13,078 | 0.0% |
| Utility plant in service | 1,942,071 | 3.4% | 1,855,665 | 3.4% |
| Assets held for future use | - | | 1,833 | |
| Construction work in progress | 21,427 | | 17,946 | |
| Total utility plant | 1,963,498 | | 1,875,444 | |
| Accumulated depreciation | (574,093) | | (536,867) | |
| Utility plant-net | $1,389,405 | | $1,338,577 | |

Accumulated depreciation does not include $187.4 million and $169.9 million at December 31, 2006 and 2005, respectively, which represent accrued asset removal costs reflected on the balance sheets as regulatory liabilities (see Note 1., “Plant and Property and Accrued Asset Removal Costs”).

The following table summarizes our investments in non-utility plant at December 31:

| Thousands, except percentages | 2006 Amount | 2006 Weighted Average Depreciation Rate | 2005 Amount | 2005 Weighted Average Depreciation Rate |
|---|---|---|---|---|
| Non-utility storage | $34,652 | | $34,486 | |
| Other | 4,820 | | 4,953 | |
| Non-utility plant in service | 39,472 | 2.5% | 39,439 | 2.6% |
| Construction work in progress | 3,180 | | 1,397 | |
| Total non-utility plant | 42,652 | | 40,836 | |
| Less accumulated depreciation | (6,916) | | (5,990) | |
| Non-utility plant – net | $35,736 | | $34,846 | |

The following table summarizes our other long-term investments, including financial investments in life insurance policies accounted for at fair value based on cash surrender values, equity investments in certain partnerships and joint ventures accounted for under the equity or cost methods, and a leveraged lease investment in an aircraft, at December 31:

| Thousands | 2006 | 2005 |
|---|---|---|
| Life insurance cash surrender value | $45,234 | $46,555 |
| Aircraft leveraged lease | - | 6,884 |
| Real estate partnership | - | 1,502 |
| Note receivable | 526 | 1,237 |
| Gas pipeline and other | 1,369 | 1,434 |
| Electric generation | 856 | 839 |
| Total other investments | $47,985 | $58,451 |

***Aircraft Leveraged Lease***. In 1987, we invested in a Boeing 737-300 aircraft, which is leased to Continental Airlines for 20 years under a leveraged lease agreement, which expires in March 2007. We have reclassified these amounts into current assets due to our expectation of selling the asset in 2007.

***Real Estate Partnership.*** In 2006, we sold our investment in a real estate partnership and received $1.8 million in cash, realizing a gain of $0.3 million on the sale.

***Gas Pipeline***. A wholly-owned subsidiary of Financial Corporation, KB Pipeline Company, owns a 10 percent interest in an 18-mile interstate natural gas pipeline.

***Electric Generation.*** At December 31, 2006, Financial Corporation held ownership interests ranging from 25 to 41 percent in wind power electric generation projects located in California. The wind-generated power is sold to Pacific Gas and Electric Company and Southern California Edison Company under long-term contracts. In January 2005, Financial Corporation sold its limited partnership interests in three electric generating systems (see Note 2).

FASB Interpretation No. 46(R), "Consolidation of Variable Interest Entities," provides guidance for determining whether consolidation is required for entities over which control is achieved through means other than voting rights, know as "variable interest entities." We do not have any significant interests in variable interest entities. See Note 1, "New Accounting Standards—Adopted Standards—Variable Interest Entities."

## 10. FAIR VALUE OF FINANCIAL INSTRUMENTS:

The estimated fair value of NW Natural's financial instruments has been determined using available market information and appropriate valuation methodologies. The following are financial instruments whose carrying values are sensitive to market conditions:

| | Dec. 31, 2006 | | Dec. 31, 2005 | |
|---|---|---|---|---|
| Thousands | Carrying Amount | Estimated Fair Value | Carrying Amount | Estimated Fair Value |
| Long-term debt including amount due within one year | $546,500 | $595,564 | $529,500 | $579,382 |

Fair value of the long-term debt was estimated using market prices in effect on the valuation date. Interest rates for debt with similar terms and remaining maturities were used to estimate fair value for long-term debt issues.

## 11. USE OF FINANCIAL DERIVATIVES:

We enter into forward contracts and other related financial transactions for the purchase of natural gas that qualify as derivative instruments under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149 (collectively referred to as SFAS No. 133). We primarily utilize derivative financial instruments to manage commodity prices related to natural gas supply requirements.

In the normal course of business, we generally enter into index-price physical forward natural gas commodity purchase (gas supply) contracts to meet the requirements of core utility customers. We also enter into financial derivatives, up to prescribed limits, to hedge price variability related to the physical contracts. Derivatives entered into prudently for future gas years prior to the PGA filing receive SFAS No. 71 regulatory deferral treatment. Derivatives contracts entered into for core utility customer requirements after the annual PGA rate has been set are subject to the PGA incentive sharing mechanism, whereby 67 percent of the changes in fair value are deferred as regulatory assets or liabilities and the remaining 33 percent is recorded to the income statement. During the fourth quarter of 2006, we entered into a number of financial derivatives after our PGA filing. The unrealized mark-to-market losses on these hedges totaled $9.5 million, of which $2.9 million was subject to sharing and was recorded as a loss, with the remainder deferred.

The mark-to-market adjustment at December 31, 2006 for all derivatives was a total unrealized loss of $43.2 million consisting of the following: unrealized losses of $40.3 million on swap contracts, $0.7 million on option contracts, $2.1 million on indexed-price physical supply contracts and $0.1 million on foreign exchange forwards.

Certain natural gas purchases from Canadian suppliers are payable in Canadian dollars, including both commodity and demand charges, which exposes us to adverse changes in foreign currency rates. Foreign currency forward contracts are used to hedge the fluctuation in foreign currency exchange rates for our commodity and commodity-related demand charges paid in Canadian dollars. Foreign currency contracts for commodity costs are purchased on a month-to-month basis because the Canadian cost is priced at the average noon-day exchange rate for each month. Foreign currency contracts for demand costs have terms ranging up to 12 months. The gains and losses on the shorter-term currency contracts for commodity costs are recognized immediately in cost of gas. The gains and losses on the currency contracts for demand charges are not recognized in current income but are subject to a regulatory deferral tariff and, as such, are recorded as a derivative asset or liability. These forward contracts qualify for cash flow hedge accounting treatment under SFAS No. 133. The mark-to-market adjustment at December 31, 2006 was an unrealized loss of $0.1 million. These unrealized gains and losses were subject to regulatory deferral and, as such, were recorded as a derivative asset or liability which is offset by recording a corresponding amount to a regulatory asset or regulatory liability account resulting in a nominal loss which was deferred to a regulatory account.

We did not use any derivative instruments to hedge oil or propane prices or interest rates during 2006, 2005 or 2004.

At December 31, 2006 and 2005, unrealized gains or losses from mark-to-market valuations of our derivative instruments were primarily reported as regulatory liabilities or regulatory assets because the realized gains or losses at settlement are included in utility gas costs, pursuant to regulatory deferral mechanisms. The estimated fair values of unrealized gains and losses on derivative instruments outstanding, determined using a discounted cash flow model for swaps and indexed-price contracts and a Black-Scholes model for options, were as follows:

| | Fair Value Gains (Losses) | | | |
|---|---|---|---|---|
| Thousands | Dec. 31, 2006 | | Dec. 31, 2005 | |
| | Current | Non-Current | Current | Non-Current |
| Natural gas commodity-based derivative instruments: | | | | |
| Fixed-price financial swaps | $(33,965) | $(6,313) | $159,373 | $14,417 |
| Fixed-price financial options | (678) | - | 1,871 | - |
| Indexed-price physical supply | 1,115 | (3,271) | 846 | (6,300) |
| Fixed-price physical supply | - | - | 820 | - |
| Physical options | - | - | 567 | - |
| Foreign currency forwards | (135) | - | 183 | - |
| Total | $(33,663) | $(9,584) | $163,660 | $ 8,117 |

In 2006, we realized a net loss of $20.0 million from the settlement of fixed-price financial swap contracts which were recorded as increases to the cost of gas. Net realized gains from the settlement of such contracts in 2005 and 2004 were $88.9 million and $42.4 million, respectively, and were recorded as decreases to the cost of gas. Realized losses in 2006 were offset by lower gas purchase costs from the underlying hedged floating rate physical supply contracts. The currency exchange rate in all foreign currency forward purchase contracts is included in our cost of gas at settlement; therefore, no gain or loss was recorded from the settlement of those contracts. Any change in value of cash flow hedge contracts that is not included in regulatory recovery is included in other comprehensive income.

As of December 31, 2006, all of the natural gas commodity price swap contracts mature by October 31, 2008 and all of the natural gas commodity call option contracts mature by April 30, 2007.

## 12. COMMITMENTS AND CONTINGENCIES:

### Lease Commitments

We lease land, buildings and equipment under agreements that expire in various years through 2045. Rental expense under operating leases was $4.4 million, $4.1 million and $4.5 million for the years ended December 31, 2006, 2005 and 2004, respectively. The table below reflects the future minimum lease payments due under non-cancelable leases at December 31, 2006. Such payments total $55.9 million for operating leases. The net present value of payments on capital leases less imputed interest was $0.6 million. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities, vehicles and computer equipment.

| Millions | 2007 | 2008 | 2009 | 2010 | 2011 | Later years |
|---|---|---|---|---|---|---|
| Operating leases | $4.2 | $4.1 | $4.1 | $4.1 | $4.1 | $35.3 |
| Capital leases | 0.3 | 0.2 | 0.1 | - | - | - |
| Minimum lease payments | $4.5 | $4.3 | $4.2 | $4.1 | $4.1 | $35.3 |

Gas Purchase and Pipeline Capacity Purchase and Release Commitments

We have signed agreements providing for the reservation of firm pipeline capacity under which we are required to make fixed monthly payments for contracted capacity. The pricing component of the monthly payment is established, subject to change, by U.S. or Canadian regulatory bodies. In addition, we have entered into long-term sale agreements to release firm pipeline capacity. We also enter into gas purchase agreements. The aggregate amounts of these agreements were as follows at December 31, 2006:

| Thousands | Gas Purchase Agreements | Pipeline Capacity Purchase Agreements | Pipeline Capacity Release Agreements |
|---|---|---|---|
| 2007 | $283,180 | $ 86,129 | $ 5,105 |
| 2008 | 177,943 | 75,953 | 5,105 |
| 2009 | 98,807 | 70,093 | 5,105 |
| 2010 | 47,263 | 70,339 | 4,254 |
| 2011 | 25,828 | 70,059 | - |
| 2012 through 2026 | 73,179 | 198,863 | - |
| Total | 706,200 | 571,436 | 19,569 |
| Less: Amount representing interest | 59,737 | 100,411 | 1,663 |
| Total at present value | $646,463 | $471,025 | $17,906 |

Our total payments of fixed charges under capacity purchase agreements in 2006, 2005 and 2004 were $69.2 million, $83.1 million and $89.3 million, respectively. Included in the amounts for 2006, 2005 and 2004 were reductions for capacity release sales of $3.7 million in each year. In addition, per-unit charges are required to be paid based on the actual quantities shipped under the agreements. In certain take-or-pay purchase commitments, annual deficiencies may be offset by prepayments subject to recovery over a longer term if future purchases exceed the minimum annual requirements.

Environmental Matters

We own, or have previously owned, properties that may require environmental remediation or action. We accrue all material loss contingencies relating to these properties that we believe to be probable of assertion and reasonably estimable. We continue to study the extent of our potential environmental liabilities, but due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several environmental site investigations, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot be reasonably estimated. We regularly review our remediation liability for each site where we may be exposed to remediation responsibilities. The costs of environmental remediation are difficult to estimate. A number of steps are involved in each environmental remediation effort, including site investigations, remediation, operations and maintenance, monitoring and site closure. Each of these steps may, over time, involve a number of alternative actions, each of which can change the course of the effort. In certain cases, in addition to ourselves, there are a number of other potentially responsible parties, each of which, in proceedings and negotiations with other potentially responsible parties and regulators, may influence the course of the remediation effort. The allocation of liabilities among the potentially responsible parties is often subject to dispute and can be highly uncertain. The events giving rise to environmental liabilities often occurred many decades ago, which complicates the determination of allocating liabilities among potentially responsible parties. Site investigations and remediation efforts often develop slowly over many years. To the extent reasonably estimable, we estimate the costs of environmental liabilities using current technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of probable cost, we record the liability at the lower end of this range. It is likely that changes in these estimates will occur throughout the remediation process for each of these sites due to uncertainty concerning our responsibility, the complexity of environmental laws and regulations and the selection of compliance alternatives. The status of each of the sites currently under investigation is provided below.

***Gasco site.*** We own property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (the Gasco site). The Gasco site has been under investigation by us for environmental contamination under the Oregon Department of Environmental Quality's (ODEQ) Voluntary Clean-Up Program. In June 2003, we filed a Feasibility Scoping Plan and an Ecological and Human Health Risk Assessment with the ODEQ, which outlined a range of remedial alternatives for the most contaminated portion of the Gasco site. In 2006, the estimated liability for this site increased $7.2 million due to updated estimates for the completion of the Feasibility Study and Work Plan, the design and treatment system for pilot wells and the construction of a containment wall for source control. We have accrued a liability of $6.4 million for the Gasco site, which is at the low end of the range because no amount within the range is considered to be more likely than another and the high end of the range cannot be estimated.

***Siltronic (formerly Wacker) site.*** We previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (formerly Wacker Siltronic Corporation) (the Siltronic site). We are currently working with the ODEQ to develop a study of manufactured gas plant wastes on the uplands at this site. The amount of the additional accrual was deferred to a regulatory asset account pursuant to an order of the OPUC (see "Regulatory and Insurance Recovery for Environmental Matters," below).

***Portland Harbor site.*** In 1998, the ODEQ and the U.S. Environmental Protection Agency (EPA) completed a study of sediments in a 5.5-mile segment of the Willamette River (Portland Harbor) that includes the area adjacent to the Gasco site and the Siltronic site. The Portland Harbor was listed by the EPA as a Superfund site in 2000 and we were notified that we are a potentially responsible party. Subsequently, the EPA approved a Programmatic Work Plan, Field Sampling Plan and Quality Assurance Project Plan for the Portland Harbor Remedial Investigation/Feasibility Study (RI/FS). As a result of the EPA's requests for additional data after reviewing the data collected to date at the site, an additional accrual of $1.3 million was recorded in 2006 for the additional studies, regulatory oversight and related legal costs. Current information is not sufficient to reasonably estimate additional liabilities, if any, or the range of potential liabilities, for environmental remediation and monitoring after the RI/FS work plan is completed, except for the early action removal of a tar deposit in the river sediments discussed below.

In April 2004, we entered into an Administrative Order on Consent providing for early action removal of a deposit of tar in the river sediments adjacent to the Gasco site. We completed the removal of the tar deposit in the Portland Harbor in October 2005 and on November 5, 2005, the EPA approved the completed project. The estimated cost for the removal, including technical work, oversight, consultants, legal fees and ongoing monitoring, is $10.3 million. To date we have spent $9.8 million on work related to the removal of the tar deposit with a remaining liability of $0.5 million.

***Central Gas Storage Tanks.*** On September 22, 2006, we received notice from the ODEQ that our Central Service Center has been assigned a high priority for further environmental investigation. Previously there were three manufactured gas storage tanks on the premises. The ODEQ believes there could be site contamination associated with releases of condensate from stored manufactured gas, or through historic gas handling practices. In the early 1990s, we excavated waste piles and much of the contaminated surface soils and removed accessible waste from some of the abandoned piping. A negligible accrual was recorded in September 2006 for the ODEQ site assessment and legal and technical costs to investigate and determine the appropriate action, if any. In February 2007, we received notice that the site has been added to the ODEQ's list of sites where releases of hazardous substances have been confirmed and its list where it has been determined that additional investigation or cleanup is necessary. Possible costs are not currently estimable; however, we intend to seek regulatory authorization for the deferral of environmental costs related to this site (see "Regulatory and Insurance Recovery for Environmental Matters," below).

***Oregon Steel Mills site.*** See "Legal Proceedings," below.

***Regulatory and Insurance Recovery for Environmental Matters.*** In May 2003, the OPUC approved our request for deferral of environmental costs associated with specific sites, including the Gasco, Siltronic and Portland Harbor sites. The authorization, which was extended through January 2007 and expanded to include the Oregon Steel Mills site, allows us to defer and seek recovery of unreimbursed environmental costs in a future general rate case. In April 2006, the OPUC authorized us to accrue interest on deferred balances effective January 27, 2006, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. An application for extension of the regulatory approval to defer environmental costs and accrued interest is pending. As of December 31, 2006, we have paid a cumulative total of $19.1 million relating to the named sites since the effective date of the deferral authorization.

On a cumulative basis, we have recognized a total of $32.7 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $24.0 million has been spent to-date and $8.7 million is reported as an outstanding liability. At December 31, 2006, we had a regulatory asset of $27.8 million which includes $19.1 million of total expenditures to date and accruals for an additional estimated cost of $8.7 million. We believe the recovery of these costs is probable through the regulatory process. We also have an insurance receivable of $1.1 million, which is not included in the regulatory asset amount. We intend to pursue recovery of these environmental costs from our general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. We consider insurance recovery of some portion of our environmental costs probable based on a combination of factors, including a review of the terms of our insurance policies, the financial condition of the insurance companies providing coverage, a review of successful claims filed by other utilities with similar gas manufacturing facilities, and Oregon legislation that allows an insured party to seek recovery of "all sums" from one insurance company. As of January 2007, we have entered into settlement discussions with six of our major insurers, and expect to add another four insurers within the next several months. We anticipate that our overall insurance recovery effort will extend over several years.

The following table summarizes the regulatory assets and accrued liabilities relating to environmental matters at December 31, 2006 and 2005:

| | Regulatory Asset | | Accrued Liability | |
|---|---|---|---|---|
| Millions | 2006 | 2005 | 2006 | 2005 |
| Gasco site | $ 10.3 | $ 3.2 | $ 6.4 | $ 1.4 |
| Siltronic site | 0.5 | 0.3 | - | - |
| Portland Harbor site | 16.8 | 15.1 | 2.1 | 4.9 |
| Oregon Steel Mills site | 0.2 | 0.2 | 0.2 | 0.1 |
| Total | $ 27.8 | $ 18.8 | $ 8.7 | $ 6.4 |

Legal Proceedings

We are subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings, including the matters described below, cannot be predicted with certainty, we do not expect that the ultimate disposition of these matters will have a material adverse effect on our financial condition, results of operations or cash flows.

***Georgia-Pacific Corporation vs. Northwest Natural Gas Company***. On February 3, 2006, Georgia-Pacific Corporation (Georgia-Pacific) filed suit against NW Natural (Georgia-Pacific Corporation v. Northwest Natural Gas Company, Case No. CV06-151-PK, United States District Court, District of Oregon), alleging that we offered to sell natural gas to Georgia-Pacific under the interruptible sales service provisions of Rate Schedule 32 at a commodity rate set at our Weighted Average Cost of Gas. Georgia-Pacific further alleged that it accepted this offer and that we failed to perform as promised when, in October 2005, we notified Georgia-Pacific that we would have to charge Georgia-Pacific the incremental costs of acquiring gas on the open market. Georgia-Pacific also alleged breach of contract, promissory estoppel, fraudulent misrepresentation and breach of the duty of good faith and fair dealing.

On February 23, 2006, we filed a motion for summary judgment on all claims. On June 30, 2006, an order was issued by the U.S. District Court for the District of Oregon dismissing the lawsuit with prejudice and denying all pending motions, if any, as moot. On July 27, 2006, Georgia-Pacific appealed this ruling to the Ninth Circuit Court of Appeals. We have reached agreement with Georgia-Pacific on settlement terms and the lawsuit has been dismissed.

***Independent Backhoe Operator Action***. Since May 2004, five lawsuits have been filed against NW Natural by independent backhoe operators who performed backhoe services for NW Natural under contract. These five lawsuits have been consolidated into one case, in which 10 plaintiffs remain (*Law and Zuehlke, et. al. v. Northwest Natural Gas Co.,* CV-04-728-KI, United States District Court, District of Oregon). Plaintiffs allege violation of the Fair Labor Standards Act for failure to pay overtime and also assert state wage and hour claims. Plaintiffs claim that they should have been considered "employees," and seek overtime wages and interest in amounts to be determined, liquidated damages equal to the overtime award, civil penalties and attorneys' fees and costs. Additionally, plaintiffs allege that the failure to classify them as employees constituted a breach of contract under and with respect to certain employee benefits plans, programs and agreements. Plaintiffs seek an unspecified amount of damages for the value of what they would have received under these employee benefit plans if they had been classified as employees. There is insufficient information at this time to reasonably estimate the range of liability, if any, from these claims. We will vigorously contest these claims and do not expect the outcome of this litigation to have a material adverse effect on our results of operations or financial condition.

***Oregon Steel Mills site.*** In 2004, NW Natural was served with a third-party complaint by the Port of Portland (Port) in a Multnomah County Circuit Court case, *Oregon Steel Mills, Inc. v. The Port of Portland*. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Oregon Steel Mills. The Port's complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. In March 2005, motions to dismiss by ourselves and other third-party defendants were denied on the basis that the failure of the Port to plead and prove that we were in violation of law was an affirmative defense that may be asserted at trial, but did not provide a sufficient basis for dismissal of the Port's claim. No date has been set for trial and discovery is ongoing. We do not expect that the ultimate disposition of this matter will have a material adverse effect on our financial condition, results of operations or cash flows.

NORTHWEST NATURAL GAS COMPANY
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

| Thousands, except per share amounts | Quarter ended March 31 | June 30 | Sept. 30 | Dec. 31 | Total |
|---|---|---|---|---|---|
| **2006** | | | | | |
| Operating revenues | $390,391 | $170,979 | $114,914 | $336,888 | $1,013,172 |
| Net operating revenues | 125,464 | 61,747 | 41,341 | 111,624 | 340,176 |
| Net income (loss) | 41,033 | 1,994 | (9,724) | 30,112 | 63,415 |
| Basic earnings (loss) per share | 1.49 | 0.07 | (0.35) | 1.10 | 2.30* |
| Diluted earnings (loss) per share | 1.48 | 0.07 | (0.35) | 1.09 | 2.29* |
| **2005** | | | | | |
| Operating revenues | $308,777 | $153,667 | $106,667 | $341,375 | $ 910,486 |
| Net operating revenues | 120,986 | 57,649 | 41,940 | 104,418 | 324,993 |
| Net income (loss) | 39,887 | 1,140 | (8,671) | 25,793 | 58,149 |
| Basic earnings (loss) per share | 1.45 | 0.04 | (0.31) | 0.94 | 2.11* |
| Diluted earnings (loss) per share | 1.43 | 0.04 | (0.31) | 0.93 | 2.11* |

* Quarterly earnings (loss) per share are based upon the average number of common shares outstanding during each quarter. Because the average number of shares outstanding has changed in each quarter shown, the sum of quarterly earnings (loss) per share may not equal earnings per share for the year. Variations in earnings between quarterly periods are due primarily to the seasonal nature of our business.

NORTHWEST NATURAL GAS COMPANY

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

| COLUMN A | COLUMN B | COLUMN C | | COLUMN D | COLUMN E |
|---|---|---|---|---|---|
| | | Additions | | Deductions | |
| | Balance at beginning of period | Charged to costs and expenses | Charged to other accounts | Net Write-offs | Balance at end of period |
| Thousands (year ended Dec. 31) | | | | | |
| 2006 | | | | | |
| Reserves deducted in balance sheet from assets to which they apply: | | | | | |
| Allowance for uncollectible accounts | $3,067 | $3,036 | $0 | $3,070 | $3,033 |
| 2005 | | | | | |
| Reserves deducted in balance sheet from assets to which they apply: | | | | | |
| Allowance for uncollectible accounts | $2,434 | $3,034 | $0 | $2,401 | $3,067 |
| 2004 | | | | | |
| Reserves deducted in balance sheet from assets to which they apply: | | | | | |
| Allowance for uncollectible accounts | $1,763 | $3,312 | $0 | $2,641 | $2,434 |

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## ITEM 9A. CONTROLS AND PROCEDURES

### (a) Evaluation of Disclosure Controls and Procedures

As of December 31, 2006, the principal executive officer and principal financial officer of the Company have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (Exchange Act)). Based upon that evaluation, the principal executive officer and principal financial officer of NW Natural have concluded that such disclosure controls and procedures are effective to ensure that information required to be disclosed by us and included in our reports filed with or furnished to the Securities and Exchange Commission under the Exchange Act is accumulated and communicated to our management as appropriate to allow timely decision regarding required disclosure.

### (b) Changes in Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Exchange Act Rule 13a-15(f). There have been no changes in our internal control over financial reporting that occurred during our most recent fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 9A.

Management's Report on Internal Control Over Financial Reporting and The Report of Independent Registered Public Accounting Firm appear under Item 8.

## ITEM 9B. OTHER INFORMATION

None.

## PART III

### ITEM 10. DIRECTORS, EXECUTIVE OFFICERS OF THE REGISTRANT AND CORPORATE GOVERNANCE

Information concerning our Board of Directors, its Committees and the Audit Committee financial expert contained in NW Natural's definitive Proxy Statement for the May 24, 2007 Annual Meeting of Shareholders is hereby incorporated by reference. The information concerning "Section 16(a) Beneficial Ownership Reporting Compliance" and "Corporate Governance" contained in our definitive Proxy Statement for the May 24, 2007 Annual Meeting of Shareholders is hereby incorporated by reference.

| Name | Age at Dec. 31, 2006 | Positions held during last five years |
|---|---|---|
| Mark S. Dodson | 61 | President and Chief Executive Officer (2003- ); President, Chief Operating Officer and General Counsel (2001-2002). |
| Michael S. McCoy | 63 | Executive Vice President, Customer and Utility Operations (2000-2006). |
| Gregg S. Kantor | 49 | Executive Vice President (2006 - ); Senior Vice President, Public and Regulatory Affairs (2003-2006); Vice President, Public Affairs and Communications (1998-2002). |
| David H. Anderson | 45 | Senior Vice President and Chief Financial Officer (2004- ); Chief Financial Officer, TXU Gas Company (2004); Senior Vice President, Principal Accounting Officer and Controller (2003-2004); Vice President of Investor Relations and Shareholder Services, TXU Corp. (1997-2003). |
| Margaret D. Kirkpatrick | 52 | Vice President and General Counsel (2005- ); Partner, Stoel Rives LLP (1991- 2005). |
| Lea Anne Doolittle | 51 | Vice President, Human Resources (2000- ). |
| J. Keith White | 53 | Vice President, Business Development and Energy Supply (2007- ); Managing Director, Gas Operations and Wholesale Services (2005-2006); Managing Director and Chief Strategic Officer (2003-2005); Director, Strategic Development (2003); Director, Corporate and Business Development (2001-2003); Director, Business Development (1998-2001). |
| David R. Williams | 53 | Vice President, Utility Services (2007- ); Director, Acquire Customers (2006); Director, Gas Operations (2005-2006); General Manager, Utility Operations (1999-2004) |
| Grant M. Yoshihara | 51 | Vice President, Utility Operations (2007- ); Managing Director, Utility Services (2005-2006); General Manager, Consumer Services (2003-2004); General Manager, Marketing, Development and Utility Operations (2000-2002). |
| Stephen P. Feltz | 51 | Treasurer and Controller (1999- ). |
| C. J. Rue | 61 | Secretary (1982- ); Assistant Treasurer (1987- ). |
| Richelle T. Luther | 38 | Assistant Secretary (2002- ); Associate, Stoel Rives LLP (1997-2002). |

Each executive officer serves successive annual terms; present terms end on May 24, 2007. There are no family relationships among our executive officers.

NW Natural has adopted a Code of Ethics for all employees, including our chief executive officer, chief financial officer and principal accounting officer, and a Financial Code of Ethics that applies to senior financial employees, both of which are available on our website at www.nwnatural.com.

ITEM 11. EXECUTIVE COMPENSATION

The information concerning "Executive Compensation" and "Report of the Organization and Executive Compensation Committee on Executive Management Compensation" contained in our definitive Proxy Statement for the May 24, 2007 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2006 is reflected in Part III, Item 10, above.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth information regarding compensation plans under which equity securities of NW Natural are authorized for issuance as of December 31, 2006 (see Note 4 to the Consolidated Financial Statements):

| | **(a)** Number of securities to be issued upon exercise of outstanding options, warrants and rights | **(b)** Weighted-average exercise price of outstanding options, warrants and rights | **(c)** Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)) |
|---|---|---|---|
| Equity compensation plans approved by security holders: | | | |
| Long-Term Incentive Plan (LTIP) (Target Award)[1] | 84,494 | n/a | 375,060 |
| Restated Stock Option Plan | 334,000 | $31.14 | 1,135,000 |
| Employee Stock Purchase Plan | 23,303 | $35.17 | 221,103 |
| Equity compensation plans not approved by security holders: | | | |
| Executive Deferred Compensation Plan (EDCP)[2] | 7,700 | n/a | n/a |
| Directors Deferred Compensation Plan (DDCP)[2] | 77,751 | n/a | n/a |
| Deferred Compensation Plan for Directors and Executives (DCP)[3] | 17,510 | n/a | n/a |
| Non-Employee Directors Stock Compensation Plan[4] | n/a | n/a | n/a |
| Total | 544,758 | | 1,731,163 |

The information captioned "Beneficial Ownership of Common Stock by Directors and Executive Officers" contained in the our definitive Proxy Statement for the May 24, 2007 Annual Meeting of Shareholders is incorporated herein by reference.

[1] Shares issued pursuant to the LTIP do not include an exercise price, but are payable by us when the award criteria are satisfied. If the maximum awards were paid pursuant to the performance-based awards outstanding at December 31, 2006, the number of shares shown in column (a) would increase by 72,994 shares and the number of shares shown in column (c) would decrease by 72,994 shares.

[2] Prior to January 1, 2005, deferred amounts were credited, at the participant's election, to either a "cash account" or a "stock account." If deferred amounts were credited to stock accounts, such accounts were credited with a number of shares of NW Natural common stock based on the purchase price of the common stock on the next purchase date under our Dividend Reinvestment and Direct Stock Purchase Plan, and such accounts were credited with additional shares based on the deemed reinvestment of dividends. At the election of the participant, deferred balances in the stock accounts are payable after termination of Board service or employment in a lump sum, in installments over a period not to exceed 10 years in the case of the DDCP, or 15 years in the case of the EDCP, or in a combination of lump sum and installments. We have contributed common stock to the trustee of the Umbrella Trusts such that the Umbrella Trusts hold approximately the number of shares of common stock equal to the number of shares credited to all participants' stock accounts.

[3] Effective January 1, 2005, the EDCP and DDCP were replaced by the Deferred Compensation Plan for Directors and Executives (DCP). The DCP continues the basic provisions of the EDCP and DDCP under which deferred amounts are credited to either a "cash account" or a "stock account." Stock accounts represent a right to receive shares of NW Natural common stock on a deferred basis, and such accounts are credited with additional shares based on the deemed reinvestment of dividends. Effective January 1, 2007, cash accounts are credited quarterly with interest at a rate equal to Moody's Average Corporate Bond Yield, while EDCP and DDCP cash accounts continue to be credited quarterly with interest at a rate equal to Moody's Average Corporate Bond Yield plus two percentage points. For the EDCP and the DDCP only, the crediting rate is subject to a six percent minimum rate. Our obligation to pay deferred compensation in accordance with the terms of the DCP will generally become due on retirement, death, or other termination of service, and will be paid in a lump sum or in installments of five or ten years as elected by the participant in accordance with the terms of the DCP. The right of each participant in the DCP is that of a general, unsecured creditor of the Company.

[4] The material features of this plan are more particularly described in Note 4 to the Consolidated Financial Statements included in this report.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information captioned "Transactions with Related Persons" and "Corporate Governance" in the Company's definitive Proxy Statement for the May 24, 2007 Annual Meeting of Shareholders is hereby incorporated by reference.

## ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned "2006 and 2005 Audit Firm Fees" in the Company's definitive Proxy Statement for the May 24, 2007 Annual Meeting of Shareholders is hereby incorporated by reference.

## PART IV

### ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) The following documents are filed as part of this report:

1. A list of all Financial Statements and Supplemental Schedules is incorporated by reference to Item 8.

2. List of Exhibits filed:

Reference is made to the Exhibit Index commencing on page 118.

## SIGNATURES

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

NORTHWEST NATURAL GAS COMPANY

Date: February 28, 2007

By: /s/ Mark S. Dodson
Mark S. Dodson, President
and Chief Executive Officer

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

| SIGNATURE | TITLE | DATE |
|---|---|---|
| /s/ Mark S. Dodson<br>Mark S. Dodson, President and Chief Executive Officer | Principal Executive Officer and Director | February 28, 2007 |
| /s/ David H. Anderson<br>David H. Anderson<br>Senior Vice President and Chief Financial Officer | Principal Financial Officer | February 28, 2007 |
| /s/ Stephen P. Feltz<br>Stephen P. Feltz<br>Treasurer and Controller | Principal Accounting Officer | February 28, 2007 |
| /s/ Timothy P. Boyle<br>Timothy P. Boyle | Director | |
| Martha L. Byorum | Director | |
| /s/ John D. Carter<br>John D. Carter | Director | |
| /s/ C. Scott Gibson<br>C. Scott Gibson | Director | |
| /s/ Tod R. Hamachek<br>Tod R. Hamachek | Director | |
| /s/ Randall C. Papé<br>Randall C. Papé | Director | February 28, 2007 |
| /s/ Richard G. Reiten<br>Richard G. Reiten | Director | |
| /s/ Kenneth Thrasher<br>Kenneth Thrasher | Director | |
| /s/ Russell F. Tromley<br>Russell F. Tromley | Director | |

## EXHIBIT INDEX

To
Annual Report on Form 10-K
For Fiscal Year Ended
December 31, 2006

| Exhibit Number | Document |
|---|---|
| 3a. | Restated Articles of Incorporation, as filed and effective May 31, 2006 and amended May 31, 2006. |
| *3b. | Bylaws as amended July 22, 2004 (incorporated herein by reference to Exhibit 3 to Form 10-Q for quarter ended June 30, 2004, File No. 1-15973. |
| *4a. | Copy of Mortgage and Deed of Trust, dated as of July 1, 1946, to Bankers Trust and R. G. Page (to whom Stanley Burg is now successor), Trustees (incorporated herein by reference to Exhibit 7(j) in File No. 2-6494); and copies of Supplemental Indentures Nos. 1 through 14 to the Mortgage and Deed of Trust, dated respectively, as of June 1, 1949, March 1, 1954, April 1, 1956, February 1, 1959, July 1, 1961, January 1, 1964, March 1, 1966, December 1, 1969, April 1, 1971, January 1, 1975, December 1, 1975, July 1, 1981, June 1, 1985 and November 1, 1985 (incorporated herein by reference to Exhibit 4(d) in File No. 33-1929); Supplemental Indenture No. 15 to the Mortgage and Deed of Trust, dated as of July 1, 1986 (filed as Exhibit 4(c) in File No. 33-24168); Supplemental Indentures Nos. 16, 17 and 18 to the Mortgage and Deed of Trust, dated, respectively, as of November 1, 1988, October 1, 1989 and July 1, 1990 (incorporated herein by reference to Exhibit 4(c) in File No. 33-40482); Supplemental Indenture No. 19 to the Mortgage and Deed of Trust, dated as of June 1, 1991 (incorporated herein by reference to Exhibit 4(c) in File No. 33-64014); and Supplemental Indenture No. 20 to the Mortgage and Deed of Trust, dated as of June 1, 1993 (incorporated herein by reference to Exhibit 4(c) in File No. 33-53795). |
| *4d. | Copy of Indenture, dated as of June 1, 1991, between the Company and Bankers Trust Company, Trustee, relating to the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4(e) in File No. 33-64014). |
| *4e. | Officers' Certificate dated June 12, 1991 creating Series A of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4e. to Form 10-K for 1993, File No. 0-994). |
| *4f. | Officers' Certificate dated June 18, 1993 creating Series B of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4f. to Form 10-K for 1993, File No. 0-994). |
| *4f.(1) | Officers' Certificate dated January 17, 2003 relating to Series B of the Company's Unsecured Medium-Term Notes and supplementing the Officers' Certificate dated June 18, 1993 (incorporated herein by reference to Exhibit 4f.(1) to Form 10-K for 2002, File No. 0-994). |

| | |
|---|---|
| *4i. | Form of Credit Agreement between Northwest Natural Gas Company and each of JPMorgan Chase Bank, NA, U.S. Bank National Association, Bank of America, NA, Wells Fargo Bank, NA and Wachovia Bank, National Association, dated as of October 1, 2005, including Form of Note (incorporated herein by reference to Exhibit 10.1 to Form 10-Q dated November 3, 2005, File No. 1-15973). |
| 4j. | Distribution Agreement, dated September 28, 2004 as amended and restated on December 7, 2006, among the Company, Merrill Lynch, Pierce Fenner & Smith Incorporated, UBS Securities LLC, J.P. Morgan Securities Inc. and Piper Jaffray & Co. |
| *4k. | Form of Secured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated October 4, 2004, File No. 1-15973). |
| *4l. | Form of Unsecured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.2 to Form 8-K dated October 4, 2004, File No. 1-15973). |
| *10j. | Transportation Agreement, dated June 29, 1990, between the Company and Northwest Pipeline Corporation (incorporated herein by reference to Exhibit 10j. to Form 10-K for 1993, File No. 0-994). |
| *10j.(1) | Replacement Firm Transportation Agreement, dated July 31, 1991, between the Company and Northwest Pipeline Corporation (incorporated herein by reference to Exhibit 10j.(2) to Form 10-K for 1992, File No. 0-994). |
| *10j.(2) | Firm Transportation Service Agreement, dated November 10, 1993, between the Company and Pacific Gas Transmission Company (incorporated herein by reference to Exhibit 10j.(2) to Form 10-K for 1993, File No. 0-994). |
| *10j.(3) | Service Agreement, dated June 17, 1993, between Northwest Pipeline Corporation and the Company (incorporated herein by reference to Exhibit 10j.(3) to Form 10-K for 1994, File No. 0-994). |
| *10j.(5) | Firm Transportation Service Agreement, dated June 22, 1994, between Pacific Gas Transmission Company and the Company (incorporated herein by reference to Exhibit 10j.(5) to Form 10-K for 1995, File No. 0-994). |
| *10j.(6) | Firm Service Agreement between the Company and Westcoast Energy Inc., dated as of April 1, 2003 (incorporated herein by reference to Exhibit 10 to Form 10-Q for quarter ended March 31, 2003, File No. 0-994). |
| 11 | Statement re computation of per share earnings. |
| 12 | Statement re computation of ratios of earnings to fixed charges. |
| 23 | Consent of PricewaterhouseCoopers LLP. |
| 31.1 | Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002. |

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| 31.2 | Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002. |
| 32.1 | Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. |

Executive Compensation Plans and Arrangements:

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| *10b. | Executive Supplemental Retirement Income Plan (2004 Restatement) (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated September 28, 2004, File No. 1-15973). |
| *10b.(1) | Supplemental Executive Retirement Plan, effective September 1, 2004 restated December 1, 2006 (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 20, 2004, File No. 1-15973). |
| *10b.(2) | Northwest Natural Gas Company Supplemental Trust, effective January 1, 2005, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.7 to Form 8-K dated December 16, 2005, File No. 1-15973). |
| *10b.(3) | Northwest Natural Gas Company Umbrella Trust for Directors, effective January 1, 1991, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.5 to Form 8-K dated December 16, 2005, File No. 1-15973). |
| *10b.(4) | Northwest Natural Gas Company Umbrella Trust for Executives, effective January 1, 1988, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.6 to Form 8-K dated December 16, 2005, File No. 1-15973). |
| *10b.(5) | Amended and Restated ESRIP Change in Control Appendix to the Executive Supplemental Retirement Income Plan, as amended and effective December 14, 2006 (incorporated herein by reference to Exhibit 10.4 to Form 8-K dated December 19, 2006, File No. 1-15973). |
| 10c. | Restated Stock Option Plan, as amended effective December 14, 2006. |
| *10c.(1) | Form of Restated Stock Option Plan Agreement (incorporated herein by reference to Exhibit 10.3 to Form 10-Q dated November 3, 2005, File No. 1-15973). |
| *10e. | Executive Deferred Compensation Plan, effective as of January 1, 1987, restated as of January 1, 2007 (incorporated herein by reference to Exhibit 10.6 to Form 8-K dated December 19, 2006, File No. 1-15973). |
| *10f. | Directors Deferred Compensation Plan, effective June 1, 1981, restated as of January 1, 2007 (incorporated herein by reference to Exhibit 10.7 to Form 8-K dated December 19, 2006, File No. 1-15973). |
| *10f.(1) | Deferred Compensation Plan for Directors and Executives effective January 1, 2005, restated as of January 1, 2007 (incorporated herein by reference to Exhibit 10.2 to Form 10-Q dated November 2, 2006, File No. 1-15973). |

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| *10g. | Form of Indemnity Agreement as entered into between the Company and each director and executive officer (incorporated herein by reference to Exhibit 10g. to Form 10-K for 1988, File No. 0-994). |
| *10i. | Non-Employee Directors Stock Compensation Plan, as amended effective December 15, 2005 (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated December 16, 2005, File No. 1-15973). |
| *10k. | Executive Annual Incentive Plan, effective January 1, 2003 (incorporated herein by reference to Exhibit 10 k. to Form 10-K for 2002, File No. 0-994) |
| *10o. | Form of amended and restated executive change in control severance agreement between the Company and each executive officer other than Mark S. Dodson (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated December 19, 2006, File No. 1-15973). |
| *10o.-1 | Amended and restated executive change in control severance agreement dated December 14, 2006 between the Company and Mark S. Dodson (incorporated herein by reference to Exhibit 10.3 to Form 8-K dated December 19, 2006, File No. 1-15973). |
| *10p. | Employment Agreement dated July 2, 1997, between the Company and an executive officer (incorporated herein by reference to Exhibit 10(a) for Form 10-Q for the quarter ended September 30, 1997, File No. 0-994). |
| *10p.-1 | Amendment dated December 18, 1997 to employment agreement dated July 2, 1997, between the Company and an executive officer (incorporated herein by reference to Exhibit 10p.-1 to Form 10-K for 1997, File No. 0-994). |
| *10p.-2 | Amendment dated September 24, 1998 to employment agreement dated July 2, 1997, as previously amended, between the Company and an executive officer (incorporated herein by reference to Exhibit 10(g) to Form 10-Q for the quarter ended September 30, 1998, File No. 0-994). |
| *10p.-3 | Employment Agreement dated December 20, 2002, between the Company and an executive officer (incorporated herein by reference to Exhibit 10p.-3 to Form 10-K for 2002, File No. 0-994). |
| *10p.-4 | Amendment dated December 14, 2006 to employment agreement dated December 20, 2002 between the Company and Mark S. Dodson (incorporated herein by reference to Exhibit 10.8 to Form 8-K dated December 19, 2006, File No. 1-15973). |
| *10v. | Northwest Natural Gas Company Long-Term Incentive Plan, as amended and restated effective July 26, 2001 (incorporated herein by reference to Exhibit 10(c) to Form 10-Q for the quarter ended June 30, 2001, File No. 0-994). |
| *10w. | Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.8 to Form 8-K dated December 16, 2005, File No. 1-15973). |

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| *10w.(1) | Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated February 21, 2007, File No. 1-15973). |
| *10x. | Form of Restricted Stock Bonus Agreement under the Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.9 to Form 8-K dated December 16, 2005, File No. 1-15973). |
| *10x.(1) | Restricted Stock Bonus Agreement with an executive officer dated July 26, 2006 (incorporated by reference to Exhibit 10.1 to Form 8-K dated July 28, 2006, File No. 1-15973). |
| *10z.(1) | Summary of non-employee director compensation, effective January 1, 2005 (incorporated herein by reference to Form 8-K dated October 3, 2006, File No. 1-15973). |
| *10aa. | Form of Consent dated December 14, 2006 entered into by each executive officer (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 19, 2006, File No. 1-15973). |

* Incorporated herein by reference as indicated