NORTHWEST NATURAL GAS CO
Form 10-K
March 02, 2009
Table of Contents

UNITED STATES

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, 2008

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

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 [ ] No [X]

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X] No [ ]

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, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of accelerated filer, large accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer [X]	Accelerated Filer [ ]
Non-accelerated filer [ ]	Smaller Reporting Company [ ]

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

As of June 30, 2008, the registrant had 26,435,373 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 $1,211,499,354.

At February 23, 2009, 26,501,188 shares of the registrant s Common Stock (the only class of Common Stock) were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement of the registrant s, to be filed in connection with the 2009 Annual Meeting of Shareholders, are incorporated by reference in Part III.

Table of Contents

NORTHWEST NATURAL GAS COMPANY

Annual Report to Securities and Exchange Commission

on Form 10-K

For the Fiscal Year Ended December 31, 2008

Table of Contents

Table of Contents

GLOSSARY OF TERMS

Average weather: equal to the 25-year average degree days based on temperatures established in our 2003 Oregon general rate case.

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 at atmospheric pressure and 60 degrees Fahrenheit. One hundred thousand Btu s equal one therm.

Core utility customers: residential, commercial and industrial customers on firm service from the utility.

Decoupling: a rate mechanism, also referred to as our conservation tariff, 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 temperatures from 65 degrees Fahrenheit.

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

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.

General rate case: a periodic filing with state or federal 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 users) 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. To reach a liquid form at atmospheric pressure, natural gas must be cooled to approximately -260 degrees Fahrenheit.

Purchased Gas Adjustment (PGA): a regulatory mechanism for adjusting customer rates due to changes in the cost to acquire commodity supplies.

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.

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.

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 the utility to adjust customers bills during the winter heating season to reduce variations in margin recovery due to fluctuations from average temperatures.

Table of Contents

Forward-Looking Statements

Statements and information included in this report that are not purely historical are forward-looking statements within the safe harbor provisions and meaning of Section 21E of the Securities Exchange Act of 1934, as amended (Exchange Act). Forward-looking statements include, but are not limited to, statements concerning plans, objectives, goals, strategies, future events or performance, trends, cyclicality, growth, development of projects, exploration of new gas supplies, estimated expenditures, costs of compliance, potential efficiencies, impacts of new laws and regulations, projected obligations under retirement plans, adequacy of and shift in mix of gas supplies, and adequacy of regulatory deferrals. Such statements are expressed in good faith and we believe 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 with respect to allowed rates of return, industry and rate structure, timely and adequate 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 laws and regulations including but not limited to tax laws and policies, 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, including regulatory allowance or disallowance of costs based on regulatory prudency reviews;
- economic factors that could cause a severe downturn in the national economy, in particular the economies of Oregon and Washington, thus affecting demand for natural gas;
- unanticipated population growth or decline and changes in market demand caused by changes in demographic or customer consumption patterns;
- the creditworthiness of customers, suppliers and financial derivative counterparties;
- market conditions and pricing of natural gas relative to other energy sources;
- unanticipated changes that may affect our liquidity or access to capital markets, including volatility in the credit environment and financial services sector;
- capital market conditions, including their effect on financing costs, the fair value of pension assets and on pension and other postretirement benefit costs;
- application of the Oregon Public Utility Commission 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, natural phenomena including earthquakes or other geohazard events, and other pandemic events;
- competition for retail and wholesale customers and our ability to remain price competitive;
- our ability to access sufficient gas supplies and our dependence on a single pipeline transportation company for natural gas transmission;
- property damage associated with a pipeline safety incident, as well as risks resulting from uninsured damage to our property, intentional or otherwise;
- financial and operational risks relating to business development and investment activities, including the Palomar pipeline and the proposed Gill Ranch underground gas storage facility;
- unanticipated changes in interest or foreign currency exchange rates or in rates of inflation;

Table of Contents

- changes in estimates of potential liabilities relating to environmental contingencies or in timely and adequate regulatory or insurance recovery for such liabilities;
- unanticipated changes in future liabilities and legislation relating to employee benefit plans, including changes in key assumptions;
- our ability to transfer knowledge of our aging workforce and maintain a satisfactory relationship with the union that represents a majority of our workers;
- 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 the timing of such projects;
- federal, state or other regulatory actions related to climate change; and
- legal and administrative proceedings and settlements.

These forward-looking statements involve risks and uncertainties. We may make other forward-looking statements from time to time, including statements in press releases and public conference calls and webcasts. All forward-looking statements made by us are based on information available to us at the time the statements are made and speak only as of the date on which such statement is made. 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. Some of these risks and uncertainties are discussed at Item 1A., Risk Factors of Part I and Item 7. and Item 7A., Management s Discussion and Analysis of Financial Condition and Results of Operations and Quantitative and Qualitative Disclosures About Market Risk, respectively, of Part II of this report.

Table of Contents

NORTHWEST NATURAL GAS COMPANY

PART I

ITEM 1. BUSINESS

General

Northwest Natural Gas Company (NW Natural) was incorporated under the laws of Oregon in 1910. Our company and its predecessors have supplied gas service to the public since 1859. We have been doing business as NW Natural since September 1997. We maintain operations in Oregon, Washington and California and conduct business through NW Natural, two wholly-owned subsidiaries and a joint venture. A reference to NW Natural (we, us or our) in this report means NW Natural and it subsidiaries and joint venture unless otherwise noted.

Business Segments

We operate in two primary reportable business segments, Local Gas Distribution and Gas Storage. We also have other investments and business activities not specifically related to one of these two reporting segments which we aggregate and report as Other.

Local Gas Distribution

We are principally engaged in the distribution of natural gas in Oregon and southwest Washington. We refer to this business segment as our local gas distribution or utility. Local gas distribution involves building and maintaining a safe and reliable pipeline distribution system, purchasing gas from producers and marketers, contracting for the transportation of gas over pipelines from the supply basins to our service territory, and reselling the gas to customers subject to 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 96 percent of our consolidated assets and 85 percent of our consolidated net income in 2008 were 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 southwest Washington counties bordering the Columbia River. We provide gas service in 124 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 2008, we had approximately 662,000 total customers, consisting of 599,000 residential, 62,000 commercial and 1,000 industrial sales and transportation customers. Approximately 90 percent of our customers are located in Oregon and 10 percent are in Washington. Industries we serve 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 revenues.

4

Utility Gas Supply, Storage and Transportation Capacity

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 customer 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 large customers between sales service and transportation-only service. We perform sensitivity analyses 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 are:

- ***Reliability*** Ensuring a gas resource portfolio that is sufficient to satisfy core utility customer requirements under extremely cold weather conditions as described below in Source of Supply Design Day Sendout;
- ***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 commodity 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 our gas acquisition strategy, we employ a gas purchasing strategy that emphasizes a diversity of supply, liquidity, price risk management, asset optimization and regulatory alignment as described below.

Diversity of supply. There are three primary means by which we diversify our gas supply acquisitions: regional supply basins; contract types; and contract durations.

Our utility obtains its gas supplies from three key supply basins. They are the Alberta and British Columbia regions in Canada, and the Rocky Mountain region in the United States. We believe that gas supplies available in the western United States and Canada are adequate to serve our core utility requirements for the foreseeable future, but we are considering shifting more of our supply mix to the U.S. Rocky Mountains based on projections of declining gas imports from western Canada and increased gas production in the U.S. Rocky Mountains. We believe that the cost of natural gas coming from these regions will continue to track market prices, but there may be price discounts on supplies from the U.S. Rocky Mountains in the near term due to of the limited amount of transmission capacity to transport that supply to existing markets. Several projects have been proposed recently to increase pipeline capacity out of the U.S. Rocky Mountain region. In addition, we also believe the potential development of a liquefied natural gas (LNG) import terminal would benefit the Pacific Northwest. If constructed, an LNG import terminal would introduce a new source of gas supply to our utility customers and the region, thereby increasing the diversity of available sources of energy and increasing the overall supply of natural gas available to meet future demand growth in the region.

Table of Contents

We typically enter into gas purchase contracts for:

- year-round baseload supply;
- additional baseload supply for the winter heating season;
- winter heating season contracts where we have the option to call on all or some 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 non-heating season baseload contracts, non-heating season contracts where the supplier has the option to supply gas to us on a daily basis, and seasonal exchange purchase and sale contracts. We try to maintain a diversified portfolio of purchase arrangements.

We also use a variety of multi-year contract durations to avoid having to re-contract a significant portion of our supplies every year. See Core Utility Market Basic Supply, below.

Trading Points. 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 U.S. 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 or floor price, or both, on a floating price contract (referred to as calls, puts, and collars); 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, in an effort to maximize the value of our gas storage and pipeline capacity, we contract with an independent energy marketing company that optimizes our unused capacity when those assets are not serving the needs of our core utility customers. This asset optimization service performed by the independent energy marketing company produces cost savings that are refunded to core utility customers, as well as generates incremental revenues which are included in our gas storage business segment. See Note 2.

Regulatory alignment. Mechanisms for gas cost recovery are designed to be fair, and balance the interests of customers and shareholders. In general, utility rates are designed to recover the cost of, but not earn a return on, the gas commodity purchased, and we attempt to minimize risks associated with cost recovery through:

- re-setting customer rates annually for changes in forecasted purchased gas costs and customer deferrals of prior year s actual versus forecasted gas purchase costs. (see Part II, Item 7., Results of

Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment);

Table of Contents

aligning customer and shareholder interests, such as through the use of our purchased gas adjustment (PGA) incentive sharing mechanism, weather normalization, conservation, and gas storage sharing mechanisms (see Part II, Item 7., Results of Operations Regulatory Matters); 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 customers primarily consists of the purchase price paid to suppliers, charges paid to pipeline companies to store and transport the gas to our distribution system and gains or losses related to commodity hedge contracts entered into in connection with the purchase of gas for core utility customers.

Supply cost. Volatility in natural gas commodity prices has increased dramatically over the last several years primarily due to shifts in the balance of supply and demand, which has been affected by the level of gas imports, regional accessibility to gas supplies, supply disruptions, changes in the global energy markets, availability of pipeline capacity to transport natural gas from region to region, and changes in general economic conditions. 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 U.S. Rocky Mountains, where some growth in gas production is expected to continue for the foreseeable future.

Transportation cost. Pipeline transportation rates charged by our pipeline suppliers had been relatively stable until recently. In 2006, two of the five major pipelines used by NW Natural filed with the Federal Energy Regulatory Commission (FERC) for significant rate increases which were implemented in 2007. Pipeline transportation rate increases are generally passed on to our customers through state-approved annual PGA mechanisms.

Gas price 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 and by entering into financial hedge contracts to fix or limit the price of gas commodity purchases.

Managing the Cost of Gas

We manage natural gas commodity price risk through active physical and financial hedging programs Our financial hedge 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., Quantitative and Qualitative Disclosures About Market Risk Credit Risk Credit exposure to financial derivative counterparties. Under our financial hedge program, we enter into commodity swaps, puts, calls and collars anywhere from one month up to five years into the future. Realized gains or losses from financial commodity hedge contracts are treated as reductions or increases to the cost of gas.

In addition to the prices that are hedged through financial contracts, we also use gas storage as a physical hedge. We purchase and inject about 15 to 20 percent of our annual gas supply requirements into storage during the summer when demand and gas prices are generally lower. The 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. The other two storage facilities are owned and operated by our primary pipeline supplier.

The intended effect of our physical and financial hedging programs are to manage the price exposure for a majority of our gas supply portfolio for the following gas contract year, with prices hedged for approximately 60 percent of year round supplies and 80 percent or more of our expected winter-heating season supplies based on forecasted customer requirements.

Source of Supply Design Year and 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 utility customers. For this purpose, we develop a composite design year that is based on the coldest weather experienced over the last 20 years in our service territory. We start with the coldest heating season during the last 20 years and then modify it to include the coldest single 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 also assume that all usage by interruptible customers will be curtailed on the design day. Our projected sources of delivery for design day firm utility customer sendout total approximately 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 cost and dependency on firm interstate pipeline 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. Similar cold temperatures experienced in December 2008 produced very high sendout days but they were still about 20 percent below our 2004 record. Accordingly, we believe that our supplies would be sufficient to meet firm customer demand if we were to experience design day conditions. We will continue to evaluate and update our forecasts of design day requirements in connection with our integrated resource plan (IRP) process (see Integrated Resource Plan, below).

The following table shows the sources of supply that are projected to be used to satisfy the design day sendout for the 2008-2009 winter heating season:

Projected Sources of Supply for Design Day Sendout

Sources of Supply	Therms (in millions)	Percent
Firm supplier contracts	3.3	37
Off-system firm storage contracts	1.1	12
Mist underground storage (utility only)	2.4	27
Company-owned LNG storage	1.8	20
Recall agreements	0.4	4
Total	9.0	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 sufficiently satisfies the needs of existing customers and positions the utility to meet future requirements.

8

Core Utility Market Basic Supply

We purchase gas for our core utility customers from a variety of suppliers located in western Canada and the U.S. Rocky Mountain area. Currently, about 60 70 percent of our supply comes from Canada, with the balance coming primarily from the U.S. Rocky Mountain region, but we are considering shifting more of our supply mix to the U.S. Rocky Mountains based on projections of declining gas imports from western Canada and increased gas production in the U.S. Rocky Mountains. At January 1, 2009, we had 28 firm contracts with 15 suppliers and remaining terms ranging from five months to six years, which provide for a maximum of 2.2 million therms of firm gas per day during the peak winter heating season and 1.1 million therms per day during the entire year. These contracts have a variety of pricing structures and purchase obligations. During 2008, we purchased 831 million therms of gas under the following contract durations:

Contract Duration (primary terms)	Percent of Purchases
Long-term (one year or longer)	50
Short-term (more than one month, less than one year)	16
Spot (one month or less)	34
Total	100

We regularly renew or replace our gas supply contracts with new agreements with 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), our daily contract requirements are provided by multiple sources with no more than three suppliers providing between 10 and 15 percent of our average daily contract volumes. Firm year-round supply contracts have remaining terms ranging from one to six years. All term gas supply contracts use price formulas tied to monthly index prices. 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 2008, new short-term purchase agreements were entered into with nine suppliers. These agreements have a variety of pricing structures and provide for a total of up to 1.5 million therms per day during the 2008-2009 heating season. We intend to enter into new purchase agreements in 2009 for equivalent volumes of gas with existing or new suppliers, as needed, to replace contracts that will expire during 2009.

We also buy gas on the spot market as needed to meet core utility customer 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 a small amount of gas from a non-affiliated producer in the Mist gas field in Oregon. The production area is situated near our underground gas storage facility. Current production is approximately 19,000 therms per day from about 17 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.

Table of Contents

Core Utility Market Peaking Supply and Storage

We supplement our firm gas supplies with gas from storage facilities we own or that are contractually committed to us. Gas is generally purchased and stored during periods of low demand for use at a later time 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 gas prices are generally lower.

Underground storage. We provide daily and seasonal peaking gas supplies to our Oregon core utility customers from our underground gas storage facility in the Mist gas storage field. Including the latest expansions in 2008, this facility has a maximum daily deliverability of 5.1 million therms and a total working gas capacity of about 16 Bcf. In 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. In May 2008, a total of 100,000 therms per day of Mist storage capacity that had previously been available for storage services was recalled and committed to use for core utility customers. This is the first recalled capacity since 2004. Under our regulatory agreement with the OPUC, storage capacity that has been developed and used by the gas storage segment can be recalled as needed and transferred to utility rate base at our original cost less accumulated depreciation, with a corresponding rate increase to customers to reflect the cost of service. The core utility market now has 2.4 million therms per day of deliverability and approximately 9 Bcf of working gas committed from the Mist storage facility. As storage capacity is recalled to serve core utility customers, we may be able to develop new storage capacity to replace it and continue serving interstate customers.

We also have contracts with The Williams Companies Northwest Pipeline (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 two 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.

Company-owned LNG. We own and operate two LNG storage facilities in our Oregon service territory that liquefy gas for storage during the summer months so that it is available for withdrawal during the peak winter heating season. These two facilities provide a maximum combined daily deliverability of 1.8 million therms and a total seasonal capacity of 17 million therms.

Recallable capacity from transportation customers. 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 390,000 therms per day of recallable capacity and supply. The contracts for 52,000 therms per day of year-round capacity expire in July 2009. Two of the three recallable capacity/supply contracts are renewed on a year-to-year basis, while the third expires in 2010 at which time we would expect to renew annually.

Transportation

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 s

Table of Contents

gas flows are bi-directional and 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 U.S. Rocky Mountain supply basins. In 2003 a federal order requiring Northwest Pipeline to replace its 26-inch mainline from the Canadian border to our service territory underscored the need for pipeline transportation diversity. 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 developing plans to build a pipeline project (Palomar) that would connect TransCanada Pipelines Limited s (TransCanada) Gas Transmission Northwest (GTN) interstate transmission line to our gas distribution system. In August 2007, we entered into an agreement with GTN for the purpose of jointly developing, owning and operating this proposed pipeline. Additionally, we entered into precedent agreements to become a shipper on the Palomar Pipeline. If constructed, this pipeline would provide an alternate transportation path for gas purchases from Alberta that currently move through the Northwest Pipeline system (See Part II, Item 7., 2009 Outlook).

Rates. FERC establishes rates for interstate pipeline transportation service under long-term transportation agreements within the U.S., and Canadian federal or provincial authorities establish rates 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 September 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 November 2011. It provides up to 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 s pipeline and two upstream pipelines in Canada, which match the amount of Northwest Pipeline capacity northward into Alberta, Canada.

We also have an agreement with Northwest Pipeline that previously extended into 2009 for approximately 350,000 therms per day of firm transportation capacity from the U.S. Rocky Mountain region. In February 2008, we extended the term of this contract through 2044. Also in February 2008, we executed an agreement with a third party to take assignment of their firm gas supply transportation contract starting no earlier than 2012 nor later than 2017, with the term extending through 2046. This contract consists of 120,000 therms per day on Northwest Pipeline from the U.S. Rocky Mountain region.

In addition, we have firm long-term pipeline transportation contracts with two other major transporters located in Canada. One contract 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. Another contract 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 on this second contract 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.

Table of Contents

Integrated Resource Plan

The OPUC and WUTC have implemented IRP processes under which utilities develop plans defining alternative growth scenarios and resource acquisition strategies. Elements of these plans include:

- 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.

We filed our 2008 IRP with the OPUC and an update to our 2007 IRP with the WUTC in April 2008. In October 2008, we received notification from the WUTC that our 2007 IRP met the requirements of the Washington Administrative Code. In January 2009, the OPUC acknowledged our 2008 IRP. Although OPUC acknowledgment of the IRP does not constitute ratemaking approval of any specific resource acquisition strategy or expenditure, the OPUC generally indicates that it would give considerable weight in prudency reviews to utility actions that are consistent with acknowledged plans. The WUTC has indicated that the IRP process is one factor it will consider in a prudency review.

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, we compete primarily with electricity, fuel oil and propane. We also compete with electricity and fuel oil for commercial applications. In the industrial market, we compete with all forms of energy, including competition from third-party sellers of natural gas commodity. Competition among gas suppliers is based on price, perceived environmental impact, sustainability, reliability, efficiency and performance, market conditions, technology and legislative policy. Whether or not we provide the gas supplies to serve our transportation-eligible customers, our net margins are not materially affected because we generally do not make any margin on the commodity sales to our utility customers (see Industrial Markets, below).

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, and our operating convenience and environmental advantage over fuel oil, provides the potential for continuing growth from residential and commercial conversions. In 2008, 9,609 net new residential customers were added, primarily from single- and multi-family new construction, but also from the conversion of existing homes from oil, electric or propane appliances to natural gas. The net increase of all new customers added in 2008 was 10,329. This represents a 12-month growth rate of 1.6 percent, which is above the national average for local gas distribution companies as reported by the American Gas Association. On an annual basis, residential and commercial customers typically account for about 55 percent of our utility s total volumes delivered and about 85 percent of gross operating revenues, while industrial customers account for about 45 percent of volumes and about 13 percent of gross revenues. The remaining 2% of gross operating revenues is derived from miscellaneous services and other regulatory charges.

Table of Contents

Industrial Markets

Competition to serve the industrial and large commercial market in the Pacific Northwest has been relatively unchanged since the early 1990s in terms of numbers and types of competitors. Competitors consist of gas marketers, oil/propane sellers and electric utilities.

Industrial customers we serve 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 group accounts for a significant portion of our revenues or margins.

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 sales service rate less the commodity cost included in that rate. Therefore, we are unaffected financially if industrial customers buy commodity supplies directly from marketers rather than purchasing gas from us, as long as they remain on a tariff or contract with the same quality of service. 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 levels of service, and these choices can positively or negatively affect margin. The relative level and volatility of prices in the natural gas commodity markets, along with the availability of pipeline capacity to ship customer-owned gas, are among the primary factors that have caused some industrial customers to alternate between sales and transportation service or between higher and lower levels 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 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 several 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 competitive 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 transferring to special contracts where pricing is specifically designed to be competitive with their bypass alternative.

Table of Contents

Gas Storage

Our gas storage business segment includes natural gas storage services provided to interstate and intrastate customers in the Pacific Northwest using underground gas storage and pipeline facilities we own and operate. We also use an independent energy marketing company to provide asset optimization services for the utility under a contractual arrangement, the results of which are included in this business segment.

Currently, 3 percent of our consolidated assets and 12 percent of our consolidated net income in 2008 are related to the gas storage business segment. For each of the years ended December 31, 2008, 2007, and 2006, this business segment derived a majority of its revenues from multi-year contracts with less than 10 customers taking service at our Mist storage facility. The total working gas capacity at our Mist gas storage facility is approximately 16 Bcf. Of this capacity, approximately 9 Bcf, or 56 percent of storage capacity, is currently used by our utility, and the remaining 7 Bcf, or 44 percent, is committed to gas storage customers primarily under firm storage contracts. See Note 2 for more information on total assets and results of operations for the years ended December 31, 2008, 2007 and 2006.

Pre-tax income from gas storage at Mist and third-party optimization services using our utility s storage or transportation capacity is subject to revenue sharing with core utility customers. In Oregon, 80 percent of the pre-tax income is retained by the gas storage 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 in each case are credited to a deferred regulatory account for refund 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 activities.

We are currently in the process of developing a second underground gas storage facility and related pipeline in the Fresno, California area. This project is expected to serve the California market. We plan to move ahead with construction later this year, subject to market conditions and our ability to obtain regulatory approvals (see Gill Ranch, below).

Seasonality of business. Generally, gas storage revenues do not follow seasonal patterns similar to those experienced by the utility because rates for firm storage contracts are in the form of fixed monthly reservation charges and are not affected by customer usage. However, there is some seasonal variation from the optimization of excess utility storage and related transportation capacity. Excess capacity is usually available during the spring and summer months when the demand for gas by utility customers is low.

Customers. Our gas storage business segment generally enters into contracts with customers for firm storage capacity for terms ranging from one to 10 years. Currently, our revenues are primarily derived from a few large storage customers who provide energy related services, including natural gas distribution, electric generation and energy marketing companies. Five storage customers currently contracted account for over 90 percent of our existing gas storage capacity, with the largest customer accounting for about half of total capacity. These five customers have contracts that expire at various dates between April 2009 through March 2015, with the largest customer s contract expiring in March 2015.

Table of Contents

***Competitive conditions*.** Our existing gas storage facility faces limited competition from other west coast storage projects primarily because of its geographic location. In the future, we could face increased competition from new or expanded natural gas storage facilities as well as from natural gas pipelines and marketers.

***Interstate gas storage*.** This part of the business segment currently provides firm and interruptible gas storage services at Mist with related transportation services on the utility s system to and from Mist to interstate pipeline interconnections. The interstate storage services, and maximum rates for these services, are authorized by the FERC. The storage capacity used by this business segment has been developed as a non-utility investment by NW Natural in advance of core utility customers requirements.

***Intrastate gas storage*.** We provide intrastate gas storage services under an OPUC-approved rate schedule that includes service and site-specific qualifications. The firm storage service terms and conditions mirror the firm interstate storage service regulated by FERC, except that these customers are located and served in Oregon.

Gill Ranch. In September 2007, we announced a joint project with Pacific Gas & Electric Company (PG&E) to develop a new underground natural gas storage facility at Gill Ranch near Fresno, California (Gill Ranch). We formed a wholly-owned subsidiary of NW Natural to develop and operate the facility, Gill Ranch Storage, LLC. Our subsidiary will initially own 75 percent of the project, and PG&E will own 25 percent. The initial development of this new storage facility is expected to provide approximately 20 Bcf of underground gas storage capacity and will include approximately 27 miles of transmission pipeline when the initial phase is completed. We estimate our 75 percent share of the total project cost for the initial phase of development, which began in 2008 and is expected to continue through 2010, to be between $160 million and $180 million. In July 2008, Gill Ranch filed an application with the California Public Utilities Commission (CPUC) for a Certificate of Public Convenience and Necessity. If granted, Gill Ranch will be subject to CPUC regulation with respect to rates and will require regulatory approvals for certain activities, including but not limited to securities issuance, terms of services, systems of accounts, lien grants and sales of property. We expect the initial phase of Gill Ranch to be in-service by late 2010.

Other

We have non-utility investments and other business activities which are aggregated and reported as a business segment called Other. Although in the aggregate these investments and activities are not material, we identify and report them as a stand-alone segment based on our current organization structure and decision-making process and because these business investments and activities are not specifically related to our utility or gas storage segments. This segment primarily consists of an equity method investment in a joint venture to build and operate an interstate gas transmission pipeline in Oregon (see Part II, Item 7., 2009 Outlook Strategic Opportunities Pipeline Diversification, below) and pipeline assets in NNG Financial Corporation, as well as some operating and non-operating expenses of the parent company that cannot be charged to utility operations. Until recently, this segment also had equity investments in several windpower and solar electric generating projects in California and a Boeing 737 aircraft leased to a commercial airline. The aircraft investment was sold in April 2008, and the windpower and solar investments were sold in years prior to 2008. Approximately 1 percent of our consolidated assets and about 3 percent of 2008 consolidated net income are related to activities in the Other business segment. See Note 2 for more information on total assets and results of operations for the three years ended December 31, 2008.

Table of Contents

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates, terms of services, and systems of accounts established by the OPUC, the WUTC and the FERC. The OPUC and WUTC also regulate our issuance of securities. Approximately 90 percent of our utility operating revenues are derived from Oregon customers, and the balance is derived from Washington customers.

We periodically file general rate case and rate tariff requests with the OPUC, WUTC and FERC to change the rates we charge our utility and storage customers. With certain exceptions, our most recent agreement with the OPUC precludes us from filing a general rate case request before September 2011, but does not preclude us from filing other types of rate adjustment requests. In 2008, we filed a general rate case in Washington that was approved on December 26, 2008 with the resulting changes to rates effective on January 1, 2009 (see Part II, Item 7., Results of Operations Regulatory Matters General Rate Cases, below). We are required under our Mist interstate storage certificate authority and rate approval orders to file every three years either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for the interstate storage service. In the future, we may be subject to regulation in other states, such as California, resulting from our strategic investments such as Gill Ranch. For further information, see Part II, Item 7., Results of Operations Regulatory Matters, and Gas Storage Gill Ranch, above.

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 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 disposition. 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); an area adjacent to the Gasco and the Siltronic sites in 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); the former location of a gas manufacturing plant operated by our predecessor that is outside the geographic scope of the current Portland Harbor site (Front Street site); and the former site of three manufactured gas tanks (Central

Table of Contents

Service Center site). Based on our current assessment of regulatory and insurance recovery of environmental costs, we do not expect that the ultimate resolution of these matters will have a material adverse effect on our financial condition, results of operations or cash flows; however, if it is determined that both the insurance recovery and future rate recovery of such costs are not probable, then the costs not expected to be recovered 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 Note 12, for a further discussion of potential environmental responses, related costs and regulatory and insurance recovery.

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, proposed federal legislation and proposed or enacted state actions to develop statewide or regional programs, each of which have imposed or would impose measures to achieve reductions in greenhouse gas emissions. The outcome of federal and state climate change initiatives cannot be determined at this time, but these initiatives could produce a number of results 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 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 continue to take steps to address future greenhouse gas emission issues, including actively participating in policy development through the Oregon Governor s Task Force on Climate Change and leading efforts within the American Gas Association to promote the enactment of fair federal climate change legislation. In 2008, our current President and CEO was appointed to the newly formed Oregon Global Warming Commission. We continue to engage in policy development and in identifying ways to reduce greenhouse gas emissions associated with our operations and our customers gas use, including the introduction of the Smart Energy program, which allows customers to contribute funds to projects that offset greenhouse gases produced from their natural gas use.

Employees

At December 31, 2008, our workforce consisted of 717 members of the Office and Professional Employees International Union (OPEIU), Local No. 11, AFL-CIO, and approximately 400 management level and other non-bargaining employees. Our labor agreement (Joint Accord) with members of OPEIU that covers wages, benefits and working conditions extends to May 31, 2009, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement. Each party has served notice of intent to negotiate the terms of an agreement prior to the May 31, 2009 expiration date.

Additions to Infrastructure

We expect to make a significant level of capital expenditures for additions to utility and storage infrastructure over the next five years, reflecting continued investments in customer growth, technology, distribution system enhancements and the development of additional gas storage facilities. In 2009, utility capital expenditures are estimated to be between $100 and $110 million, and non-utility

Table of Contents

capital investments are estimated to be between $50 and $70 million for business development projects that are currently in process. For the years 2009-2013, capital expenditures for the utility are estimated to be between $450 and $500 million, while the amount for business development investments after 2009 will depend largely on future decisions about potential opportunities in gas storage and pipeline projects.

Available Information

We file annual, quarterly and special reports and other information with the Securities and Exchange Commission (SEC). Reports, proxy statements and other information filed by us can be read and copied at the public reference room of the SEC, 100 F Street, N.E., Washington, D.C. 20549. You can obtain additional information about the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website (http://www.sec.gov) that contains reports, proxy statements and other information that we file electronically. In addition, we make available on our website (http://www.nwnatural.com), 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. We intend to disclose amendments to, and any waivers from, such codes of ethics 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 May 23, 2008 that, as of that date, he was not aware of any violation by the company of the 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, 2007, 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, 2008, 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. When considering any investment in our securities, investors should consider the following information, as well as information contained in the caption Forward Looking Statements, and other documents we file with the SEC. This list is not exhaustive and our management places no priority or likelihood based on their order of presentation.

Economic risk. *Changes in the economy and in the financial markets may have a negative impact on our financial condition and results of operations.*

The global credit and financial markets have been experiencing significant disruption and volatility in recent months. At the same time the U.S. economy has slowed, unemployment rates are rising, and there has been an increase in mortgage defaults and a decrease in the value of homes and investment assets, which has adversely affected the income and financial resources of many domestic households. It is unclear whether the federal responses to these conditions will lessen the severity or duration of this economic downturn. Our operations are affected by these economic conditions. Less new housing construction, fewer conversions to natural gas, higher levels of residential foreclosures and vacancies, and personal and business bankruptcies or reduced spending could all result in a decline in energy consumption and customer growth and have a negative effect on our financial condition and results of operations.

Regulatory risk. *Regulation of our business, including changes in the regulatory environment in general, and failure of regulatory authorities to approve rates which provide for timely recovery of our costs and an adequate return on invested capital in particular, may adversely impact our financial condition and results of operations.*

The OPUC and WUTC have general regulatory authority over our utility business in Oregon and Washington, respectively, including rates and charges, the issuance of securities, services and facilities, terms of customer services, system of accounts, investments, safety standards, transactions with affiliated interests and other matters. In addition, FERC has regulatory authority over our interstate gas storage services, and the CPUC will have regulatory authority over our Gill Ranch gas storage development and operations.

The rates we charge to customers must be approved by the applicable regulatory agencies. Our rates are generally designed to allow us to recover the costs of providing such services and to earn an adequate return on our capital investment. However, we expect the rates charged to customers of Gill Ranch for gas storage services will be based on what customers are willing to pay (i.e. market-based rates) rather than on our recovery of costs plus a return on our investment. We expect to continue to make expenditures to expand, improve and operate our distribution and storage systems. Regulators can deny recovery of expenditures we make if they find that such expenditures were not prudently incurred according to their regulatory standards.

In addition, in the normal course of our business we may place assets in service or incur higher levels of operating expense before rate cases can be filed to recover those costs this is commonly referred to as regulatory lag. The failure of any regulatory commission to approve requested rate increases on a timely basis to recover increased costs or to allow an adequate return could adversely impact our financial condition and results of operations.

Gas price risk. *Higher natural gas commodity prices and volatility in the price of gas may adversely affect our results of operations and cash flows.*

In recent years, we have seen a significant increase in the volatility of natural gas commodity prices, primarily due to shifts in the balance of supply and demand. Early in 2008, we saw natural gas prices rise to record high levels as demand grew, especially for new electric power generation, which was outpacing North American gas production. Then during the second half of 2008, the price of natural gas fell significantly as our national economy fell into a recession and demand for natural gas declined while North American gas production increased. There are a number of external factors that affect the balance of natural gas supply and demand, including the level of gas imports, regional accessibility to gas supplies, supply disruptions, changes in the global energy markets, the availability of pipeline capacity to transport natural gas from region to region and changes in general economic conditions. The cost we pay for natural gas is generally passed through to our customers through an annual PGA rate adjustment in Oregon and Washington (see below). Significant increases in the commodity price of natural gas raises the cost of energy to our existing customers, thereby causing those customers to conserve or potentially switch to alternate sources of energy. Significant price increases could also cause new home builders and commercial developers to select heating systems other than natural gas. Decreases in the volume of gas we sell could reduce our earnings in the absence of decoupled rate structures, and a decline in customers could slow growth in our future earnings.

Higher gas prices may also cause us to experience an increase in short-term debt and temporarily reduce liquidity because we pay suppliers for gas when it is purchased, which can be materially in advance of when these costs are recovered through rates. Significant increases in the price of gas can also slow our collection efforts as customers experience increased difficulty in paying their higher energy bills, leading to higher than normal delinquent accounts receivable. This could contribute to higher short-term debt levels, greater expense associated with collection efforts and increased bad debt expense.

In Oregon and Washington, our utility has PGA tariffs which provide for annual revisions in rates resulting from changes in the cost of purchased gas including the expected impact on bad debt expense. In Oregon, we also have a price-elasticity adjustment that adjusts rates through the annual PGA for expected increases or decreases in customer usage due to higher or lower gas prices. The Oregon PGA tariff also provides an incentive to the Company to achieve lower gas costs such that a percentage, set annually, 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 (see Part II, Item 7., Results of Operations Regulatory Matters Rate Mechanisms). Accordingly, higher gas costs than those assumed in setting rates can adversely affect our operating cash flows, liquidity and results of operations, until such costs are recovered from customers. 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 and cash flows.

Inability to access capital market risk*. Our inability to access capital or significant increases in the cost of capital could adversely affect our business.*

Our ability to obtain adequate and cost effective short-term and long-term financing depends on our credit ratings as well as the liquidity and stability of financial markets. Our businesses rely on access to capital markets, including the commercial paper markets, to finance our operations, construction expenditures and other business requirements, and to refund maturing debt that cannot be funded entirely by internal cash flows. A negative change in our ratings by credit rating agencies could adversely affect our financing cost, liquidity and access to capital. Additionally, downgrades in our current credit ratings below investment-grade could cause additional delays in accessing the credit markets by the utility while we seek supplemental regulatory approval from the OPUC. Disruptions in the capital and credit markets could also adversely affect our ability to access short-term and long-term capital. Our access to funds under committed short-term credit facilities, which are currently provided by a number of banks, is dependent on the ability of the participating banks to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Longer disruptions in the bank or capital financing markets as a result of economic uncertainty, changing or increased regulation of the financial sector, or failure of major financial institutions could adversely affect our access to capital and may negatively impact our ability to run the business and make strategic investments.

Table of Contents

Hedging risk. *Our risk management policies and hedging activities cannot eliminate the risk of commodity price movements and other financial market risks, and our hedging activities 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, while our use of debt and equity financing exposes us to interest rate and other financial market risks. We attempt to manage these exposures and mitigate our risks through enforcement of established risk limits and risk management procedures, including hedging activities that are in accordance with our derivatives policies. These risk limits and risk management procedures may not always work as planned and cannot entirely eliminate the risks associated with hedging. Additionally, our hedging activities may cause us to incur additional expenses which could result in a material adverse effect on our operating revenues, costs, derivative assets and liabilities, and operating cash flows.

We cannot and do not hedge our entire interest rate or commodity cost exposure, and the unhedged exposure will vary over time. Gains or losses experienced through hedging activities, including carrying costs, generally flow through the PGA mechanism or are recovered in future general rate cases, thereby limiting our exposure to earnings volatility on a year-to-year basis. However, the hedge transactions we enter into for the utility are subject to a prudency review by the OPUC and WUTC, and, if deemed imprudent, those expenses may be disallowed, which could have a material adverse effect on our operating revenues, costs, derivative assets and liabilities, and operating cash flows. In addition, actual business requirements and available resources may vary from forecasts, which are used as the basis for our hedging decisions, and could cause our exposure to be more or less hedged than we anticipated. Additionally, if our derivative instruments and hedging transactions do not qualify for hedge accounting under Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Hedging Activities, our hedges may not be effective and our results of operations, cash flows and financial condition could be adversely affected.

We also have credit related exposure to financial derivative counterparties. In general, we require our counterparties to have a high level investment-grade credit rating at the time the derivative instrument is entered into, and we specify limits on the contract amount and duration based on each counterparty s credit rating. Nevertheless, counterparties owing us money or physical natural gas commodities could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected. Although our valuations take into account the expected probability of default by counterparties, an actual default by a particular counterparty could have a greater impact than we estimated. Additionally, under most of our hedging arrangements, any downgrade of our senior secured long-term debt credit rating below investment grade could allow our counterparties to require us to post cash, a letter of credit or other form of collateral, which would expose us to additional costs and may trigger significant increases in draws from our borrowing facilities.

Customer growth risk. *Our results of operations may be negatively affected if we are unable to sustain customer growth rates in our local gas distribution business.*

Our margins and earnings growth have largely depended upon the sustained growth of our residential and commercial customer base due, in part, to the new construction housing market, conversions of customers to natural gas from other fuel sources and growing commercial use of natural gas. Should there be continued weakness in the new housing market, a slowdown in the conversion market or declining use of natural gas by our residential and commercial customer base, there could be an adverse long-term impact on our utility margin, earnings and cash flows.

Table of Contents

Risk of competition. *Our gas distribution and storage businesses are subject to increased competition which could negatively affect our results of operations.*

In the residential market, our gas distribution business competes primarily with suppliers of electricity, fuel oil and propane. 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 at times eroded, or in some cases eliminated, the competitive price advantage of natural gas over other energy sources. Also, technological improvements in other energy sources could erode our competitive advantage. If natural gas prices continue to rise relative to other energy sources, it may negatively affect our ability to attract new customers, and our residential, commercial and industrial customers may use alternative sources of energy or bypass our systems in favor of contracts with lower per-unit costs, which could have a negative impact on our customer growth rate and results of operations.

Additionally, our existing gas storage segment currently faces limited competition from other west coast storage projects primarily because of its geographic location. In the future, we could face increased competition from new or expanded natural gas storage facilities, interstate pipelines and gas marketers seeking to provide or arrange transportation, storage and other services for customers.

Reliance on third parties to supply natural gas risk. *We rely on third parties to supply all of the natural gas we store and deliver, and limitations on our ability to obtain supplies could have a material impact on our financial results.*

Our ability to provide natural gas for current and future sales depends upon our ability to obtain and deliver supplies of natural gas, as well as our ability to acquire supplies directly from new sources. Certain factors including the following may affect our ability to acquire and deliver natural gas to our current and future customers: suppliers or other third parties control over the drilling of new wells and facilities to transport natural gas to our distribution system; competition for the acquisition of natural gas; priority allocations on transmission pipelines; impact of severe weather disruptions to natural gas supplies such as occurred with Hurricane Katrina in 2005; the regulatory and pricing policies of federal, state and local government agencies; and the availability of Canadian reserves for export to the United States. If we are unable to obtain or are limited in our ability to obtain natural gas from our current suppliers or new sources, our financial results could be materially impacted.

Single transportation pipeline risk. *We rely on a single pipeline company for the transportation of gas to our service territory, a disruption of which could adversely impact our ability to meet our customers gas requirements.*

Our distribution system is directly connected to a single interstate pipeline, Northwest Pipeline. The pipeline s gas flows are bi-directional and 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 U.S. Rocky Mountain supply basins. 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 service disruptions.

Business development risk. *The development, construction, startup and operation of our business development projects may involve unanticipated changes or delays that could negatively impact our costs as well as our financial condition, results of operations and cash flows.*

22

Table of Contents

Business development projects involve many risks. We are in the early development stages on two strategic business development projects: the Gill Ranch gas storage facility in California, and the Palomar gas transmission pipeline in Oregon. We may also engage in other business development projects in the future. With respect to these projects, we may not be able to obtain required governmental permits and approvals, or financing, to complete our projects in a cost-efficient or timely manner. If we do not obtain the necessary regulatory approvals in a timely manner, development projects may be delayed or abandoned. There also may be startup and construction delays, construction cost overruns, inability to negotiate acceptable agreements such as rights-of-way, easements, construction, gas supply or other material contracts, changes in market prices; and operating cost increases. Additionally, natural gas storage and gas transportation markets are intensely competitive, both within the natural gas industry and with alternative sources of energy. To complete our business development projects, we will need to secure financing from willing lenders at reasonable interest rates. If the current tight credit markets persist or become more inaccessible, we may be unable to acquire the necessary financing to fund our business development projects at acceptable interest rates within a timeframe favorable for completing the project. Similarly, an inability to obtain the necessary state permits, secure acceptable financing, or arrange for sufficient supplier commitments, could impact the viability of an LNG terminal on the Columbia river and may mean that we would not proceed with the western portion of Palomar. One or more of these events may mean that our equity investments could become impaired and such impairment could have an adverse effect on our financial condition, results of operations and cash flows.

Joint partner risk. *Investing in business development projects through partnerships, joint ventures or other business arrangements decreases our ability to manage certain risks.*

We use joint ventures and other business arrangements to manage and diversify the risks of certain non-utility development projects, including Palomar and Gill Ranch, and we may acquire interests in other similar types of projects in the future. Under these types of business arrangements, we may not be able to fully direct the management and policies of the business relationships, and other participants in those relationships may take action contrary to our interests. In addition, other participants may withdraw from the project, become financially distressed or bankrupt, or have economic or other business interests or goals that are inconsistent with ours. Although we have contractual and other legal remedies to enforce our interests, if a participant in one of these business arrangements acts contrary to our interests, it could adversely impact our financial condition, results of operations and cash flows.

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

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 from insurance or through customer rates. A regulatory asset has already been recorded for some of these estimated costs pursuant to a deferral order from the OPUC. To the extent we are unable to recover these deferred costs in rates or through insurance, we would be required to reduce our regulatory asset which could adversely affect our results of operations and financial condition. In addition, disputes may arise between potentially responsible parties and regulators as to

Table of Contents

the severity of particular environmental matters and what remediation efforts are appropriate. These disputes could lead to adversarial administrative proceedings or litigation, with uncertain outcomes.

We cannot predict with certainty the amount or timing of future expenditures related to 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 an adverse effect on our results of operations, particularly if those costs are not fully recoverable from customers.

Global climate change legislation risk. *Management expects that future legislation may impose carbon constraints to address global climate change exposing us to regulatory and financial risk.*

There are a number of new federal and state legislative and regulatory initiatives being proposed and adopted in an attempt to control or limit the effects of global warming and overall climate change, including greenhouse gas emissions such as carbon dioxide. The outcome of federal and state actions to address climate change could result in a variety of regulatory programs including potential new regulations, additional requirements to fund energy efficiency activities, or other regulatory actions. These actions could result in increased compliance and other costs, additional operating restrictions, and could impact the prices we charge our customers, which could adversely affect our business practices, financial condition or results of operations.

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

We are exposed to weather risk primarily in our utility business segment. A majority of our volume is driven from gas sales made to space heating residential and commercial customers during each winter heating season. Current utility rates are based on an assumption of average weather. Weather that is warmer than average typically results in lower gas sales. Sustained cold weather could adversely affect our utility margin in the short-term as we may be required to purchase gas at spot rates in a rising price market to obtain sufficient volumes to fulfill customer requirements. Although the effects of warmer or colder weather on utility margin in Oregon are intended to be largely mitigated through the operation of our weather normalization mechanism. Oregon customers may opt out of the mechanism. Approximately 10 percent of our residential and commercial customers are in Washington where we do not have a weather normalization mechanism or conservation tariff. Furthermore, continuation of the weather normalization mechanism and conservation tariff in Oregon after October 2012, are subject to regulatory approval. As a result, we may not be fully protected against warmer than average or colder than average weather, both of which may have an adverse affect on our financial condition, results of operations and cash flows.

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

Higher gas costs and rates and an increasing national focus on energy conservation may result in increased gas conservation by customers, which can decrease sales and adversely affect our 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. The conservation tariff is scheduled to expire in October 2012 (see Results of Operations Rate Mechanisms Conservation Tariff, below). The failure of the OPUC to extend the conservation tariff in the future could adversely affect our financial condition, cash flows and results of operations. We do not have a conservation tariff in Washington.

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 are subject to a variety of operating hazards and risks that cannot be completely avoided, such as leaks, accidents, mechanical problems, fires, explosions, earthquakes, floods, 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 be recoverable through rates, which could adversely affect our financial condition and results of operations.

Business continuity risk. *We may be adversely impacted by national disasters, terrorist activities and other extreme events to which we may not able to promptly respond.*

National disasters, terrorist activities and other extreme events are a threat to our assets and operations. Companies in our industry may face a heightened risk to exposure to actual acts of terrorism that could target or impact our natural gas distribution, transmission and storage facilities and result in a disruption in our operations and ability to meet customer requirements. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Threatened or actual national disasters or terrorist activities may also disrupt capital markets and our ability to raise capital, or impact our suppliers or our customers directly. We maintain emergency planning and training programs to remain ready to respond to extreme events. However, a slow or inadequate response to extreme events may have an adverse affect on operations and earnings. We may not be able to obtain sufficient insurance to cover all risks associated with national disasters, terrorist activities and other extreme events, which could increase the risk that an event could adversely affect our operations or financial results.

Employee benefit risk. *The cost of providing pension and postretirement healthcare benefits is subject to changes in pension asset values, changing demographics and actuarial assumptions which may have an adverse effect on our financial results.*

We provide pension plans and postretirement healthcare benefits to eligible full-time employees. Our costs of providing such benefits is subject to changes in the market value of our pension fund assets, changing demographics, including longer life expectancies of beneficiaries, an expected increase in the number of eligible former employees over the next five to 10 years, increases in healthcare costs, current and future legislative changes and various actuarial calculations and assumptions. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, withdrawal rates, interest rates and other factors. These differences may result in a significant impact on the amount of pension expense or other postretirement benefit costs recorded in future periods. Sustained declines in equity markets and reductions in bond yields may have a material adverse effect on the value of our pension fund assets. In these circumstances, we may be required to recognize increased contributions and pension expense earlier than we had planned

to the extent that the value of pension assets is less than the total anticipated liability under the plans, which could have a negative impact on cash flows and results of operations.

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, and workforce disruptions could adversely affect our operations and results.*

Our ability to implement our business strategy and serve our customers in our gas distribution business is dependent upon our continuing ability to attract and retain talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new employees as our aging employees retire. Without an appropriately skilled workforce, our ability to provide quality service to our customers and meet our regulatory requirements will be challenged and this could negatively impact our earnings. Additionally, a majority of our workers are represented by Office and Professional Employees International Union Local No.11 AFL-CIO (the Union) and are covered by a collective bargaining agreement that will expire May 31, 2009. The Company and the Union are expected to negotiate an agreement, but failure to reach an acceptable collective bargaining agreement with the Union in a timely manner could result in instability in our labor relationship and work stoppages that could impact the timely delivery of our product and services, which could strain relationships with customers and state regulators and cause a loss of revenues which could adversely affect our results of operations. The terms of a revised collective bargaining agreement may increase the cost of employing our workforce, affect our ability to continue offering market-based salaries and employee benefits, limit our flexibility in dealing with our workforce, and limit our ability to change work rules and practices and implement other efficiency-related improvements to successfully compete effectively in today s competitive marketplace.

Legislative and taxing authority risk. *We are subject to governmental regulation, and our compliance with local, state and federal requirements, including taxing requirements, and unforeseen changes in or interpretations of such requirements could affect our financial condition and results of operations.*

We are subject to regulation by federal, state and local governmental authorities. We are required to comply with a variety of laws and regulations and to obtain authorizations, permits, approvals and certificates from governmental agencies in various aspects of our business. We cannot predict with certainty the impact of any future revisions or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to them. Changes in regulations or the imposition of additional regulations could negatively influence our operating environment and results of operations. For example, Oregon legislation that became effective in 2006, requires that utilities not collect in rates more income taxes than they actually pay to taxing authorities. If amounts paid differ from amounts we collect by more than $100,000 we are required to implement a rate schedule with an automatic adjustment clause to refund or surcharge the difference, which could be material.

Additionally, changes in federal, state or local tax laws and their related regulations, or differing interpretation or enforcement of applicable law by a federal, state or local taxing authority could negatively affect our results of operations. Tax law and its related regulations and case law are inherently complex. Disputes over interpretations of tax laws may be settled with the taxing authority in examination, upon appeal or through litigation. Our judgments may include reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by

Table of Contents

taxing authorities. Unforeseen changes in laws, regulations or adverse judgments may negatively affect our financial condition and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments.

ITEM 2. PROPERTIES

Our natural gas distribution system consists of approximately 13,800 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. Resource centers 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 approximately 8,500 net acres of underground natural gas storage and approximately 1,600 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 and operated 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 Oregon, as well as in California related to the Gill Ranch storage project.

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 expect to eliminate all bare steel mains and services in the system by 2021.

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

Other than the proceedings disclosed in Note 12, we have only routine nonmaterial litigation in the ordinary course of business.

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, 2008.

27

Table of Contents

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:

	2008		2007	
Quarter Ended	High	Low	High	Low
March 31	$ 50.74	$ 41.07	$ 46.34	$ 39.79
June 30	48.22	43.08	52.85	44.05
September 30	55.23	43.66	49.37	40.98
December 31	53.71	36.61	50.89	44.28

The closing quotations for our common stock on December 31, 2008 and 2007 were $44.23 and $48.66, respectively.

(B) As of December 31, 2008, there were 7,673 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 per share, adjusted for stock splits, have increased each year since 1956. Dividends per share paid during the past two years were as follows:

Payment Date	2008	2007
February 15	$ 0.375	$ 0.355
May 15	0.375	0.355
August 15	0.375	0.355
November 15	0.395	0.375
Total per share	$ 1.520	$ 1.440

The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. Our Board of Directors expects to continue paying cash dividends on our common stock on a quarterly basis. However, the declaration and amount of future dividends depend upon our earnings, cash flows, financial condition and other factors.

Table of Contents

(D) The following table provides information about purchases of our equity securities that are registered pursuant to Section 12 of the Securities Exchange Act of 1934 during the quarter ended December 31, 2008:

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			2,124,528	$ 16,732,648
10/01/08-10/31/08	1,645	$ 43.88	-	-
11/01/08-11/30/08	21,275	$ 47.83	-	-
12/01/08-12/31/08	1,349	$ 44.01	-	-
Total	24,269	$ 47.35	2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2008, 22,005 shares of our common stock were purchased on the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 2,264 shares of our common stock were purchased on the open market during the quarter under equity-based programs. During the three months ended December 31, 2008, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) We have a share repurchase program for our common stock under which we purchase shares on the open market or through privately negotiated transactions. We have Board authorization through May 31, 2009 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. For the year ended December 31, 2008, no shares of our common stock were purchased pursuant to this program. Since the program s inception in 2000 we have repurchased 2.1 million shares of common stock at a total cost of $83.3 million.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

Thousands, except per share amounts and ratio of earnings to fixed charges	For the year ended December 31, 2008	2007	2006	2005	2004
Utility operating revenues:					
Residential sales	$ 566,840	$ 555,312	$ 536,468	$ 471,502	$ 383,067
Commercial sales	298,943	298,800	290,666	250,287	200,424
Industrial - firm sales	46,579	54,567	66,986	64,507	45,259
Industrial - interruptible sales	68,978	74,876	93,107	100,740	55,380
Total gas sales revenues	981,340	983,555	987,227	887,036	684,130
Transportation	14,288	14,191	12,800	10,755	12,655
Regulatory adjustment for income taxes paid [1]	1,760	5,996			
Other	21,784	12,228	161	2,862	4,160
Total gross utility operating revenues	1,019,172	1,015,970	1,000,188	900,653	700,945
Cost of gas sold	656,504	639,094	648,081	563,772	399,176
Revenue taxes	25,072	25,001	24,840	21,633	16,865
Utility net operating revenues	337,596	351,875	327,267	315,248	284,904
Non-utility net operating revenues	18,619	17,167	12,909	9,745	6,591
Net operating revenues	$ 356,215	$ 369,042	$ 340,176	$ 324,993	$ 291,495
Net income	$ 69,525	$ 74,497	$ 63,415	$ 58,149	$ 50,572
Average common shares outstanding:					
Basic	26,438	26,821	27,540	27,564	27,016
Diluted	26,594	26,995	27,657	27,621	27,283
Earnings per share of common stock:					
Basic	$ 2.63	$ 2.78	$ 2.30	$ 2.11	$ 1.87
Diluted	$ 2.61	$ 2.76	$ 2.29	$ 2.11	$ 1.86
Dividends paid per share of common stock	$ 1.52	$ 1.44	$ 1.39	$ 1.32	$ 1.30
Total assets - at end of period	$ 2,378,152	$ 2,014,061	$ 1,956,856	$ 2,042,304	$ 1,732,195
Long-term debt	$ 512,000	$ 512,000	$ 517,000	$ 521,500	$ 484,027
Ratio of earnings to fixed charges	3.76	3.92	3.40	3.32	3.02

[1] Regulatory adjustment for income taxes paid is the result of the implementation of the utility regulation as described in Part II, Item 7., Business Segments - Utility Operations - Regulatory Adjustment for Income Taxes Paid.

Table of Contents

SELECTED FINANCIAL DATA (continued)

	For the year ended December 31,				
Thousands, except customer and gas cost per therm data	2008	2007	2006	2005	2004
Capitalization - at end of period					
Common stock equity	$ 628,373	$ 594,751	$ 599,545	$ 586,931	$ 568,517
Long-term debt	512,000	512,000	517,000	521,500	484,027
Total capitalization	$ 1,140,373	$ 1,106,751	$ 1,116,545	$ 1,108,431	$ 1,052,544
Gas sales and transportation deliveries (therms):					
Residential	428,787	398,960	382,665	371,538	352,356
Commercial	265,531	249,659	242,683	233,987	222,875
Industrial - firm	47,340	52,340	66,971	74,880	62,843
Industrial - interruptible	87,484	89,128	112,736	149,106	104,278
Total gas sales	829,142	790,087	805,055	829,511	742,352
Transportation	431,609	424,882	387,594	328,056	389,514
Total volumes delivered	1,260,751	1,214,969	1,192,649	1,157,567	1,131,866
Customers (average for period):					
Residential	594,481	580,346	564,700	545,163	525,976
Commercial	61,756	60,749	59,889	58,914	57,973
Industrial - firm	625	634	650	666	629
Industrial - interruptible	180	189	197	201	178
Transportation	136	128	99	78	106
Total customers	657,178	642,046	625,535	605,022	584,862
Customer statistics:					
Heat requirements:					
Actual degree days	4,576	4,374	4,089	4,178	3,853
Percent colder (warmer) than average	7%	3%	(4%)	(2%)	(10%)
Average annual use per customer in therms:					
Residential	721	687	678	682	670
Commercial	4,300	4,110	4,052	3,972	3,844
Gas purchased cost per therm - net (cents)	86.56	75.00	75.37	71.42	56.60

31

Table of Contents

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 (NW Natural) financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated activities for the years ended December 31, 2008, 2007 and 2006. Unless otherwise indicated, 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 NW Natural and its wholly-owned subsidiaries, NNG Financial Corporation (Financial Corporation) and Gill Ranch Storage, LLC (Gill Ranch), and an equity investment in a proposed natural gas pipeline. These accounts consist of our regulated local gas distribution business, our regulated gas storage business, and other regulated and non-regulated investments primarily in energy-related businesses. In this report, the term Utility is used to describe our regulated local gas distribution segment, and the term Non-utility is used to describe our gas storage segment (gas storage) and our other regulated and non-regulated investments and business activities (other segment) (see Strategic Opportunities, below, and 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 section to earnings per share are on the basis of diluted shares (see Note 1).

Executive Summary

Highlights of 2008:

- Consolidated net income was $69.5 million, or $2.61 per share;
- Net operating revenues decreased 3 percent from $369.0 million to $356.2 million, largely due to a $17.6 million swing in our utility s sharing of higher gas costs;
- Operations and maintenance expense decreased 6 percent or $7.1 million;
- Cash flow from operations decreased $148.9 million due to temporary working capital requirements, while our credit and liquidity position remained strong;
- General rate case was approved in Washington with a $2.7 million increase in annual revenues, effective January 1, 2009;
- Permit applications were filed for our gas storage project in California and our gas transmission pipeline project in Oregon, keeping these strategic investment opportunities on track for potential development over the next few years;
- We ranked number one in the nation among gas utilities in the 2008 J.D. Power and Associates Gas Utility Residential Customer Satisfaction Survey; and
- We raised the quarterly common stock dividend by 5 percent to $0.395 per share in the fourth quarter of 2008, making this the 53rd consecutive year of increasing dividends paid to shareholders.

Our business primarily consists of our regulated utility and gas storage operations. Factors critical to the success of the utility business include: maintaining a safe and reliable distribution system; acquiring an adequate supply of natural gas; providing distribution services at competitive prices; and being able to recover our operating and capital costs in the rates charged to customers in a

Table of Contents

reasonable and timely manner. Our utility is regulated by two state commissions, the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC). Factors critical to the success of our gas storage business include: developing additional storage capacity at competitive market prices; retaining existing customers or being able to market storage capacity to new customers; planning for the replacement of capacity that is expected to be recalled by the utility to serve growing demands of its customers; obtaining timely approval of reasonable rate increases; and with respect to future development of gas storage projects, being able to obtain financing to fund future development. Our existing gas storage business charges rates that are approved by the Federal Energy Regulatory Commission (FERC) for interstate customers or the OPUC for intrastate customers. The Gill Ranch gas storage project currently under development will be subject to regulation by the California Public Utilities Commission (CPUC), upon completion of certain milestones (see 2009 Outlook Strategic Opportunities Gas Storage Development, below).

2009 Outlook

In 2009, we intend to remain focused on improving our core businesses, enhancing our strategic position, advancing business development projects related to our primary businesses, and strengthening our organizational effectiveness. The following is a brief summary of management s plans and objectives in these four areas.

Business Improvements. We are developing and implementing new technology into our operations while honing the new processes established by the changes to our operating model over the last several years. Our goal is to integrate, consolidate and streamline operations and support our employees with new technology tools that should enable us to become more effective and efficient. We intend to continue developing new technology such as: an enterprise resource planning system, which provides an integrated comprehensive suite of business application software to more efficiently process and manage information in all parts of our business; continued deployment of our new automated dispatching system throughout the business, which provides integrated planning and scheduling with global positioning capabilities to more effectively collect and distribute data to employees in remote locations; and completing the installation of our automated meter reading system, which will convert the remaining customer meters so that all of our meters can be read electronically by the end of 2009. We expect these and other new technologies to continue supporting our new operating model, which re-aligned our operating functions into key process areas such as customer services, energy supply and gas delivery, to help centralize and standardize all of our business operations. For further discussion, see Strategic Opportunities, below.

Strategic Position. In our rapidly changing business environment, we remain focused on creating shareholder value while balancing the interests of our customers, employees and the communities we serve. In doing so, we intend to develop and re-work plans in response to our changing business environment, including potential climate change legislation as well as ongoing economic, regulatory, business development and workforce challenges and opportunities. For further discussion, see Issues, Challenges and Performance Measures, and Strategic Opportunities, below.

Business Development. In addition to exploring new growth opportunities, we intend to continue advancing key natural gas infrastructure investments during 2009, including our gas transmission pipeline project in Oregon and our gas storage project in California. For further discussion of these two projects, see Strategic Opportunities, below.

Organizational Effectiveness. Our employees continue to be our most highly valued resource. We intend to continue supporting our employees with a positive work environment, providing

33

Table of Contents

development training, and developing new technologies to achieve our goals and facilitate improvements to our operating model. For further discussion see Strategic Opportunities, below.

Issues, Challenges and Performance Measures

Managing the business in a period of gas price volatility. Our gas acquisition strategy is primarily designed to secure sufficient supplies of natural gas to meet the needs of our utility s residential, commercial and industrial customers on firm service. Equally important, however, is our strategy to hedge gas prices for a significant portion of our annual purchase requirements based upon our utility s gas load forecast for core utility customers. We have hedged gas prices for the majority of our gas purchases for the gas contract year that began on November 1, 2008, and we believe we have sufficient supplies of natural gas to meet the needs of our core utility customers. Although gas prices reached historically high levels during the third quarter of 2008, the price of natural gas has declined significantly in recent months and is currently below the prices embedded in our customers rates through our annual purchased gas adjustment (PGA). Gas costs lower or higher than those set in the PGA may positively or negatively impact earnings, respectively, due to an incentive sharing mechanism in Oregon. Higher gas costs are also likely to affect our competitive advantage because they could reduce our ability to add residential and commercial customers and potentially cause industrial customers to shift their energy needs to alternative fuel sources. In October 2008, the OPUC approved a change to the PGA incentive sharing mechanism that allows us to select a cost-sharing ratio annually. The PGA cost-sharing ratio, along with gas hedging strategies and inventories in storage, enables us to manage and reduce earnings risk exposure due to higher gas costs. We believe the modification to the Oregon PGA better aligns customer and shareholder interests. In Washington, where we recover 100 percent of our actual gas purchase costs from customers, there has been no change to the PGA mechanism (see Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, below).

Economic weakness and financial market stress. The overall weakness in the U.S. economy, including disruption in the global credit and financial markets, increasing numbers of foreclosures and bankruptcies, lower rates of new housing construction, and volatility in energy prices, has resulted in significant negative pressure on consumer demand and business spending. These conditions could have a negative impact on our financial results including certain key performance measures such as margins, customer growth rates, bad debt expense, and net interest charges. Our customer growth rate, which in recent years has slowed but continues at a rate above the national average, declined to 1.6 percent during 2008 compared to 2.4 percent in 2007. Based on current market conditions, we expect customer growth rates in 2009 to continue at or near 2008 levels, or possibly lower if economic conditions deteriorate further, but our growth rate should remain above the national average due to a relatively low market penetration of natural gas in our service territory, the forecasted population growth in our service territory, the potential for environmental initiatives in Oregon and Washington that could favor natural gas as an energy source, and our efforts to convert existing homes from other heating fuels to natural gas.

Our funding for strategic investment opportunities is dependent upon our ability to access capital markets and maintain working capital sufficient to meet operating requirements. We intend to continue focusing on: maintaining a strong balance sheet; providing sufficient liquidity resources; monitoring and managing critical business risks; and securing, as needed, proceeds from the issuance of equity or long-term debt securities in order to fund utility and business development capital expenditures. To help mitigate the effect of the negative economic and capital market trends referred to above, we expect to manage costs, extend short-term debt maturities, maintain higher cash balances, increase the aggregate commitment amount under existing or new credit facilities as needed, and access capital markets to secure proceeds from the issuance of long-term securities for capital expenditure requirements. If we are unable to secure financing to fund certain strategic opportunities, we may look at potentially re-prioritizing the use of existing resources or consider delaying investments until market conditions improve.

We believe that, despite the current economic and credit market environment, our financial condition, including our liquidity position, is strong and we can access capital at reasonable costs. See Part I, Item 1A., Risk Factors, above and Financial Condition Liquidity and Capital Resources, below.

Strategic Opportunities

Business Process Improvements. To address our economic and competitive challenges, we intend to re-assess business processes for continuous improvements. Our goal is to integrate, consolidate and streamline operations and support our employees with new technology tools that enable us to become more effective and efficient. In 2008, we implemented the first phase of our new enterprise resource planning (ERP) system, and in February 2009 we implemented the second phase. This new ERP system provides a comprehensive suite of business application software that interfaces with our existing customer information and automated dispatching systems. We expect this new ERP system to improve overall operating efficiencies by automating:

- the integration of systems and data;
- the control procedures with auditable financial and operational workflows; and
- certain areas of our monthly closing and financial reporting process.

In 2006, we automated the reading of gas meters on approximately one-third of our customers meters. The meters equipped with this technology now electronically transmit usage data to receiving devices located in our vehicles as they are driven in the area, substantially reducing the labor costs associated with manually reading those customer meters. In 2008, we initiated a project to automate the reading of gas meters (AMR) for our remaining customers. The capital cost of this project is estimated to be $30 million, and in January 2009 we filed for regulatory recovery of this investment. Also in 2008, we initiated an automated dispatching system, which provides integrated planning and scheduling with global positioning system capabilities to more effectively collect and distribute data. These technology investments and other initiatives are expected to facilitate process improvements and contribute to long-term operational efficiencies throughout NW Natural.

Pipeline Diversification. Currently, we depend on a single interstate pipeline company to ship gas supplies to our system. Palomar Gas Transmission, LLC, (Palomar) is a wholly-owned subsidiary of Palomar Gas Holdings, LLC, (PGH). PGH is owned 50 percent by NW Natural and 50 percent by TransCanada Gas Transmission Northwest s (GTN). Palomar is seeking to build and operate a 217-mile natural gas transmission pipeline in Oregon to serve our utility and the growing markets in Oregon and other parts of the western United States. The Palomar pipeline would extend west from an interconnection with GTN s existing interstate transmission mainline near Madras, Oregon to an interconnection with NW Natural s gas distribution system near Molalla, Oregon and then extend further west to additional interconnections including a possible connection to one of the several liquefied natural gas (LNG) terminals proposed to be built on the Columbia River. Palomar would

Table of Contents

diversify NW Natural s delivery options and enhance the reliability of service to our utility customers by providing an alternate transportation path for gas purchases from different regions in western Canada and the U.S. Rocky Mountains. Palomar would also provide our utility customers with access to a new source of gas supply if an LNG terminal is built on the Columbia River. The Palomar pipeline would be regulated by the FERC. In December 2008, Palomar filed for a Certificate of Public Convenience and Necessity with the FERC.

Palomar continues to work on the planning and permitting phase of the project, which is expected to extend through 2010. The total cost for planning and permitting is estimated to be between $40 million and $45 million, 50 percent of which is our investment based on our ownership interest. At December 31, 2008, the amount we had invested was $14.2 million. The total cost estimate for the entire 217-mile pipeline, if constructed, is estimated to be between $700 million and $800 million, with our current 50 percent share estimated at between approximately $350 million and $400 million. During 2009 and 2010, PGH will continue to evaluate market conditions and project status to determine if and when to proceed with construction of all or some portion of the project. Palomar has executed binding precedent agreements with shippers, including our own utility, for a majority of the current design capacity on the pipeline. These agreements also provide commitments of credit support to the project. We will continue to assess project risks and evaluate the project costs and fair value of our investment on a quarterly basis, including a valuation of the available credit support.

Gas Storage Development. In September 2007, we announced a joint project with Pacific Gas & Electric Company (PG&E) to develop an underground natural gas storage facility near Fresno, California. We formed a wholly-owned subsidiary, Gill Ranch, to plan, develop and operate the facility. In July 2008, Gill Ranch filed an application with the CPUC for a Certificate of Public Convenience and Necessity. In December 2008, the CPUC indicated that our application qualified for a Mitigated Negative Declaration, which allows an expedited review process. We expect to establish the application review schedule with the CPUC early in 2009 and to receive a decision on our application by the end of 2009. Gill Ranch will become subject to CPUC regulation regarding various matters including, but not limited to, securities issuances, lien grants and sales of property. We estimate our share of the total cost of this project to be between $160 and $180 million. Our share represents 75 percent of the total cost of the initial phase of storage development for an estimated 20 Bcf of gas storage capacity and approximately 27 miles of gas transmission pipeline during the 2008 to 2010 period. The initial phase of gas storage at Gill Ranch is currently scheduled to be in-service by late 2010.

Earnings and Dividends

Net income was $69.5 million, or $2.61 per share, for the year ended December 31, 2008, compared to $74.5 million, or $2.76 per share, and $63.4 million, or $2.29 per share, for the years ended December 31, 2007 and 2006, respectively. Returns on equity for these three years were 11.4 percent, 12.5 percent and 10.7 percent, respectively.

2008 compared to 2007:

Factors contributing to decreased earnings were:

- a $5.5 million loss in utility margin from our regulatory share of gas cost increases in 2008 compared to a margin gain of $12.1 million in 2007 from gas cost decreases;
- a $4.2 million decrease in utility margin from a lower customer surcharge related to regulatory adjustments for income taxes paid;

Table of Contents

- a $3.8 million increase in depreciation expense primarily due to increased utility plant in service;
- a $2.9 million decrease in margin due to a temporary mark-to-market gain in 2007; and
- a $1.6 million decrease in utility margin from industrial customers due to weaker economic conditions.

Partially offsetting the above factors were:

- a $7.1 million increase in utility margin from higher sales volumes to residential and commercial customers due to colder weather and customer growth, after decoupling and weather mechanism adjustments;
- a $7.1 million decrease in operation and maintenance expense, partially due to higher costs in 2007 for strategic initiatives, and partially due to lower bonuses and employee benefit costs in 2008;
- a $3.4 million decrease in income tax expense due to lower taxable income;
- a $1.1 million after-tax gain from the sale of our investment in an aircraft leased to a commercial airline; and
- a $0.8 million increase in utility margin due to curtailment charges for use by a small number of industrial customers during cold weather.

2007 compared to 2006:

Positive factors contributing to increased earnings were:

- a $9.7 million increase in utility margin from higher sales volumes to residential and commercial customers due to customer growth;
- a $6.0 million increase in utility margin from a regulatory adjustment for income taxes paid;
- a $4.0 million increase in utility margin from our regulatory share of gas cost savings, up from $8.1 million in 2006 to $12.1 million in 2007;
- a $5.8 million increase in utility margin from temporary mark-to-market adjustments on derivative contracts, with a $2.9 million gain realized in 2007 and a $2.9 million loss realized in 2006; and
- a $4.2 million increase in margin from gas storage operations, due to an expansion of firm storage capacity and higher revenues sharing from asset optimization.

Partially offsetting the above positive factors were:

- a $3.9 million increase in depreciation expense, primarily related to increased utility plant in service;
- a $5.9 million increase in operations and maintenance expense due to higher bonuses tied to improved operating results and increases for certain strategic initiatives including utility maintenance projects and training; and
- a $7.8 million increase in income tax expense related to higher taxable income.

Dividends paid on our common stock were $1.52 a share in 2008, compared to $1.44 a share in 2007 and $1.39 a share in 2006. The current indicated annual dividend rate is $1.58 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

Table of Contents

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 and judgments include accounting for:

- regulatory cost recovery and amortizations;
- revenue recognition;
- derivative instruments and hedging activities;
- pensions;
- 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. Within the context of our critical accounting policies and estimates, management is not aware of any reasonably likely events or circumstances that would result in materially different amounts being reported. For a description of recent accounting pronouncements that could have an impact on our financial condition, results of operations or cash flows, see Note 1.

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 required to 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, 2008 and 2007 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 deliveries 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, 2008 and 2007 were $102.7 million and $78.0 million, respectively. The increase in accrued unbilled revenues at year-end 2008 was primarily due to higher volumes reflecting colder weather and higher gas prices included in customer rates. If the estimated percentage of unbilled volume at December 31, 2008 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 $4.4 million, $0.4 million and $0.4 million, respectively.

Utility revenues may also include the recognition of a regulatory adjustment for income taxes paid. This revenue adjustment reflects an OPUC rule whereby we are required to implement a rate refund or a rate surcharge to utility customers. This refund or surcharge is accrued based on the estimated difference between income taxes paid and income taxes authorized to be collected in rates for the tax year (see Results of Operations Business Segments Utility Operations Regulatory Adjustment for Income Taxes Paid, below).

Non-utility revenues, derived primarily from our gas storage business segment, are recognized upon delivery of the service to customers. Revenues from asset optimization, which are included in our gas storage segment, are recognized when services are provided by the independent energy marketing company in accordance with our contractual agreement. Our current asset optimization agreement includes guaranteed amounts which are recognized pro-rata on a monthly basis over the contract term.

Accounting for Derivative Instruments and Hedging Activities

Our financial derivatives and gas acquisition policies set forth guidelines for using financial derivative instruments to support prudent risk management strategies. 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 meet the definition of a derivative instrument 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

Table of Contents

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 recorded 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). Derivative contracts outstanding at December 31, 2008 were measured at fair value using models or other market accepted valuation methodologies derived from observable market data. The estimate of fair value may change significantly from period-to-period depending on market conditions and prices. These changes may have an impact on our results of operations, but the impact would largely be mitigated due to the majority of our derivatives activities being subject to regulatory deferral treatment. For estimated fair values on unrealized gains and losses at December 31, 2008 and 2007, see Note 11.

Commodity-based derivative contracts entered into by the utility after our annual PGA filing for the current gas contract period are subject to a regulatory incentive sharing mechanism in Oregon (see Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, below). The portion not deferred to a regulatory account pursuant to that sharing agreement is recognized either in current income for contracts not qualifying for hedge accounting or in other comprehensive income for contracts qualifying for hedge accounting. Our interest rate swap qualifies for hedge accounting under SFAS No. 133, assuming the swap is highly effective.

Derivative hedge contracts are subject to a hedge effectiveness test to determine the financial statement treatment of each specific derivative. As of December 31, 2008, all of our derivatives were effective economic hedges and either qualified or were expected to qualify for regulatory deferral or hedge accounting treatment. We use the hypothetical derivative method under SFAS No. 133 to determine the hedge effectiveness of our interest rate swap which qualifies as a cash flow hedge. We extended the effective date of our interest rate swap from December 1, 2008 to April 1, 2009 which resulted in an ineffectiveness of $1.5 million. In accordance with SFAS No. 71, we have reclassified this amount to regulatory assets. The ineffectiveness for all other derivative contracts is determined using the dollar offset method under SFAS No. 133. The effectiveness test applied to financial derivatives is dependent on the type of derivative and its use.

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

Thousands	2008	2007	2006
Net gain (loss) on commodity-price swaps utility	$ 34,256	$ (41,954)	$ (18,849)
Net gain (loss) on commodity-price options utility	1,527	(662)	(1,160)
Subtotal on commodity utility	35,783	(42,616)	(20,009)
Net gain (loss) on foreign currency forward purchases utility	(728)	662	355
Total realized net gain (loss)	$ 35,055	$ (41,954)	$ (19,654)

Realized gains (losses) from commodity hedges 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. Realized gains (losses) from interest rate hedges are recorded as reductions (increases) to interest charges over the term of the underlying debt issuances. Unrealized gains and losses from commodity hedges, foreign currency contracts and interest rate hedges, which reflect quarterly mark-to-market valuations, are generally not recognized in current income or other comprehensive income, but are recorded as regulatory liabilities or regulatory assets, and are offset by a corresponding balance in non-trading derivative assets or liabilities (see Note 11).

Table of Contents

Accounting for Pensions

We maintain two qualified non-contributory defined benefit pension plans covering a majority of our 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. Effective January 1, 2007, the Retirement Plan for Non-Bargaining Unit Employees and the Welfare Benefits Plan for Non-Bargaining Unit Employees were closed to anyone hired or rehired. Instead, non-bargaining unit employees hired or re-hired after December 31, 2006 are provided an enhanced Retirement K Savings Plan benefit. Benefits provided to bargaining unit employees under the retirement plan for bargaining unit employees were not affected by these changes.

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 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.

SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, requires balance sheet recognition of the overfunded or underfunded status of 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 pursuant to SFAS No. 71 to record the overfunded or underfunded status as a regulatory asset or regulatory liability, rather than including it as AOCI under common equity (see Regulatory Accounting , above, and Note 1, Industry Regulation).

A number of factors are considered in developing pension assumptions, including evaluations of relevant discount rates, an evaluation of expected long-term investment returns based on asset classes and target asset allocations, and expected changes in salaries and wages, analyses of past retirement plan experience and current market conditions and input from actuaries and other consultants. For the December 31, 2008 measurement date, we reviewed and updated:

- our pension discount rate assumptions from a range of 6.75 to 6.87 percent to a range of 6.44 to 6.72 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 (S&P) or Aa3 or higher by Moody s Investors Service (Moody s);
- our expected rate of future compensation increases from a range of 4.0 to 5.0 percent to a range of 3.5 to 5.0 percent;
- our expected long-term return on plan assets remained unchanged at 8.25 percent; and
- other key assumptions as needed.

Table of Contents

At December 31, 2008, our net pension liability (benefit obligations minus market value of plan assets) for the two qualified defined benefit plans increased by $96.6 million compared to 2007. Poor equity and bond market performance had a significant impact on the fair value of plan assets resulting in the large increase in our unfunded pension liability. Changes in valuation assumptions impact our benefit obligations. Benefit obligations at December 31, 2008 increased $7.4 million due to a decrease in our discount rate assumptions and increased by $5.0 million due to updating our mortality tables.

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. As of December 31, 2008, the actual annualized returns on plan assets, net of management fees, for the past one-year, five-years, 10-years and since December 1980 were (27.18) percent, 1.82 percent, 2.97 percent and 10.10 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 2008 Pension Costs	Impact on Benefit Obligations at Dec. 31, 2008
Discount rate	(0.25%)	$ 785	$ 7,809
Expected long-term return on plan assets	(0.25%)	$ 431	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

We account for income taxes in accordance with SFAS No. 109, Accounting for Income Taxes, and Financial Accounting Standards Board (FASB) Interpretation No. 48 (FIN 48), Accounting for Uncertainty in Income Taxes, an Interpretation of SFAS No. 109, Accounting for Income Taxes, which require that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. SFAS No. 109 and FIN 48 also require that deferred tax assets be reduced by a valuation allowance if it is more likely than not that some portion or all of the deferred tax asset will not be realized. Our net long-term deferred tax liability totaled $257.8 million at December 31, 2008. This liability is estimated based on the expected future tax consequences of items recognized in the financial statements. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our tax returns. For state income tax and other taxes, judgment is also required with respect to the apportionment among the various jurisdictions. A valuation allowance is recorded if we expect that it is more likely than not that our deferred tax assets will not be realized. At December 31, 2008, we did not have a valuation allowance due to our expectation that all of these assets will be realized.

Table of Contents

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, 2008 and 2007, we had regulatory assets representing differences between book and tax basis related to pre-1981 property of $69.9 million and $68.6 million, respectively, and recorded an offsetting deferred tax liability for the same amounts (see Note 1, Income Tax Expense). We received authorization from the OPUC and WUTC in 2008 to accelerate the recovery of these pre-1981 regulatory assets through future utility rates (see Regulatory Accounting, above, and Notes 1 and 8).

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. 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 environmental liabilities and related costs we develop estimates based on a review of information available from recently completed studies and negotiations involving several sites. Using sampling data, feasibility studies, existing technology and enacted laws and regulations, we estimate that the total future expenditures for environmental investigation, monitoring and remediation are $35.9 million as of December 31, 2008. It is our policy to accrue the full amount of such liability when information is sufficient to reasonably estimate the amount of probable liability. When information is not available to reasonably estimate the probable liability, or when only the range of probable liabilities can be estimated and no amount within the range is more likely than another, then it is our policy to accrue at the lower end of the range. Accordingly, due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot be reasonably estimated. Therefore, we have recorded the liabilities at an amount that reflects the most likely estimate or the low end of the range.

We will continue to seek recovery of such costs through insurance and through customer rates, and we believe recovery of these costs is probable. If it is determined that both the insurance recovery and future rate recovery of such costs are not probable, the costs will be charged to expense in the period such determination is made (see Note 12).

Table of Contents

Results of Operations

Regulatory Matters

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates and systems of accounts by the OPUC, WUTC and FERC. The OPUC and WUTC also regulate our issuance of securities. In 2008, approximately 90 percent of our utility gas volumes were delivered to, and 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 Oregon and Washington economies in general, and by the pace of growth in the residential and commercial markets in particular, 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

Oregon. In our most recent general rate increase in Oregon, which was effective September 1, 2003, the OPUC authorized rates to customers based on a return on shareholders equity (ROE) of 10.2 percent. In 2007, in connection with the renewal of our conservation tariff and weather normalization rate mechanism, the OPUC approved a stipulation that restricts us from filing a general rate case with the OPUC prior to September 1, 2011, subject to certain exceptions. Under the agreement, we would be allowed to file a general rate case if an extraordinary event occurs or significant investments are required on behalf of our customers and we are unable to reach agreement regarding alternative forms of cost recovery outside of a general rate case. These exceptions might include additional investments in our pipeline integrity management program. This agreement does not impact our ability to file annual rate adjustments to reflect changes in gas purchase costs under our PGA mechanism or our ability to collect or refund prior year s gas cost deferrals. See Rate Mechanisms Purchased Gas Adjustment, below.

Washington. In December 2008, an all-party stipulated agreement regarding our Washington general rate case was approved by the WUTC. As part of the stipulation, the WUTC authorized rates to our customers based on a ROE of 10.1 percent, which was consistent with a rate of return on total long-term capitalization of 8.4 percent. These new customer rates went into effect on January 1, 2009. Under these new rates, our annual revenue requirements will increase by approximately $2.7 million, or 3 percent. Although we agreed not to file another general rate case in Washington before January 2010, the parties agreed that we may file separately for a decoupling mechanism upon completion of a trial program currently being conducted by another utility, which is expected to be completed during 2009.

Federal. We are required under our Mist interstate storage certificate authority and rate approval orders to file every three years either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for our interstate storage services. We filed a cost and revenue study and an associated petition for rate approval in April 2008. As a result of that proceeding, the current maximum cost-based rates for our interstate gas storage services were approved by FERC in August 2008, with our maximum rates unchanged from the levels approved by FERC in 2005. The maximum cost-based rates are designed to reflect updated costs related to the further development of the Mist gas storage facility from 2005 to 2008. Additionally, we made a filing

Table of Contents

in December 2008 to obtain FERC approval to revise the depreciation rates associated with Mist assets used to derive the cost-based interstate storage rates. In that proceeding, which is currently pending, we are requesting FERC approval to revise the depreciation rates used for the Mist interstate storage services to match the depreciation rates for the same assets that were recently adjusted under state regulation. We do not expect the approval of these new depreciation rates to have a material impact on our maximum rates approved by FERC, or any immediate impact on the actual rates currently charged to interstate storage customers.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are established each year under PGA 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, 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.

In October 2008, the OPUC and WUTC approved rate changes effective on November 1, 2008 under our PGA mechanisms. The effect of the rate changes was to increase the average monthly bills of Oregon residential customers by 14 percent and those of Washington residential customers by 21 percent.

Additionally, in October 2008, the OPUC approved changes to our PGA incentive sharing mechanism. Under the Oregon PGA mechanism, 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. Under the prior Oregon PGA incentive sharing mechanism effective through October 31, 2008, 67 percent of the difference was to be 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 purchased gas costs.

Under the new Oregon PGA incentive sharing mechanism, effective November 1, 2008, we are required to select, by August 1 of each year, either an 80 percent deferral or 90 percent deferral of higher or lower gas costs such that the impact on current earnings from the gas cost sharing is either 20 percent or 10 percent, respectively. As was the case under the prior mechanism, we will be subject to an annual earnings review to evaluate the utility s financial performance. Under both the prior and the new sharing mechanism, if earnings exceed a threshold level, then 33 percent of the amount above the threshold will be deferred for future refund to customers. Under the prior Oregon PGA incentive mechanism, effective through the end of October 2008, the deferral was 67 percent of gas cost differences and the threshold level was equal to our authorized ROE of 10.2 percent plus 300 basis points. Under the new mechanism, if we select the 80 percent deferral, we retain all of our earnings up to 150 basis points above the currently authorized ROE, or if we select the 90 percent deferral, we retain all of our earnings up to 100 basis points above the currently authorized ROE. For the PGA year in Oregon beginning on November 1, 2008, we selected the 80 percent deferral of gas cost differences. The earnings threshold is currently subject to adjustment up or down each year depending on movements in long-term interest rates.

In 2008 and 2007, the earnings threshold after adjustment for long-term interest rates was 13.1 percent and 13.4 percent, respectively. No amounts were required to be refunded to customers as a

Table of Contents

result of the 2007 earnings review, and we do not expect that any amounts will be required to be refunded to customers as a result of the 2008 earnings review, which will be approved by the OPUC during the second quarter of 2009. There has been no change to the Washington PGA mechanism under which we defer 100 percent of the higher or lower actual purchased gas costs and pass that difference through to customers as an adjustment to future rates.

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 consumption patterns due to residential and commercial customers conservation efforts. The tariff is a decoupling mechanism that is intended to break the link between utility earnings and the quantity of gas consumed by customers, removing any financial incentive by the utility 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 our utility revenues.

The Oregon conservation tariff includes two components: (1) a price elasticity adjustment, which adjusts rates annually for increases or decreases from expected 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 the difference 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 filing. Baseline consumption was determined by customer consumption data used in the 2003 Oregon general rate case and is adjusted annually for customer growth and the effect of the price elasticity adjustment discussed above. See Results of Operations Comparison of Gas Distribution Operations, below.

In 2005, an independent study to measure the effectiveness of Oregon s conservation tariff mechanism recommended continuation of the tariff with minor modifications, which the OPUC approved. In September 2007, the OPUC extended our conservation tariff through October 2012.

Weather Normalization. In Oregon, the OPUC approved our use of a weather normalization mechanism through October 2012. This mechanism is designed to help stabilize the collection of fixed costs by adjusting residential and commercial customer billings based on temperature variances from average weather, with rate decreases when the weather is colder than average and rate increases when the weather is warmer than average. The mechanism is applied to our residential and commercial customers bills between December 1 and May 15 of 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, which account for about 10 percent of our utility revenues.

Regulatory and Insurance Recovery for Environmental Costs. In May 2003, the OPUC approved our request to defer unreimbursed environmental costs associated with certain named sites including those described in Note 12. Beginning in 2006, the OPUC authorized us to accrue interest on deferred environmental cost balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, this authorization has been extended through January 25, 2009. We have requested another extension through January 2010, and that request is currently pending. See Note 12.

Industrial Tariffs. In August 2006, the OPUC and WUTC approved tariff changes to the service options for our major industrial customers. The changes set forth 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.

System Integrity Program. In July 2004, the OPUC approved specific accounting treatment and cost recovery for our transmission pipeline integrity management program, a program mandated by the Pipeline Safety Improvement Act of 2002 and the related rules adopted by the U.S. Department of Transportation s Pipeline and Hazardous Materials Safety Administration. We record these costs as either capital expenditures or regulatory assets, accumulate the costs over each 12 months ending September 30, and recover the costs, subject to audit, through rate changes effective with the annual PGA in Oregon. The rate treatment for these costs expired on September 30, 2008. In February 2009, the OPUC approved a stipulated agreement to create a new, consolidated system integrity program (SIP). The new SIP would integrate the older and the proposed programs into a single program. The SIP also includes a component for a proposed distribution integrity management program, which will be implemented following issuance of new federal regulations. Costs will be tracked into rates annually, with recovery to be sought after the first $3.3 million of capital costs which are our responsibility. An annual cap for expenditures will be approximately $12 million, with any extraordinary costs above the cap to be approved with written consent of all parties.

The SIP applies to costs incurred in Oregon during the period from October 2008 to October 2011, or until the effective date of new rates adopted in the company s next general rate case. We do not have any special accounting or rate treatment for pipeline integrity costs incurred in the state of Washington.

AMR Deferral Application. In 2006, we automated the reading of gas meters on approximately one-third of our customers meters. In 2008, we initiated a project to automate the reading of gas meters for our remaining customers. The capital cost of our AMR project is estimated to be $30 million, and in January 2009 we filed for approval to defer the costs associated with the AMR project. This request is pending before the OPUC. If the request for deferral accounting is approved, we will then seek approval to recover the deferred costs in our next PGA filing.

Depreciation Study. In December 2008, the OPUC and WUTC approved our filed depreciation study and our request to change the amortization of our regulatory asset account balance on pre-1981 plant. These approvals specifically authorized the implementation of new depreciation rates in Oregon and Washington, with corresponding decrease to customer rates effective January 1, 2009. The new amortization rates on pre-1981 plant, with a corresponding increase to customer rates, became effective January 1, 2009 in Washington and will be effective November 1, 2009 in Oregon. The implementation of these new rates will have the effect of decreasing depreciation expense and increasing effective income tax expense rates, both of which will be offset by a corresponding change in utility operating revenues. In addition, in December 2008 we filed our depreciation study with FERC requesting approval to apply these same new depreciation rates for our gas storage business assets. If approved, we expect the new depreciation rates to be effective as of January 1, 2009. Our FERC filing is currently pending.

Table of Contents

Business Segments - Utility Operations

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 revenues to offset changes in margin resulting from increases or decreases in residential and commercial customer consumption. We also have a weather normalization mechanism that adjusts customer bills up or down to offset changes in margin resulting from above- or below-average temperatures during the winter heating season (see Results of Operations Regulatory Matters Rate Mechanisms, above). Both mechanisms are designed to reduce the volatility of our utility earnings.

2008 compared to 2007:

Total utility margin decreased $14.3 million or 4 percent in 2008 compared to 2007 even though residential and commercial customers contributed an additional $7.1 million to margin in 2008, including the effects of the weather normalization and decoupling mechanisms. Total utility volumes sold and delivered in 2008 increased by 4 percent over last year due to the colder than average weather and 1.6 percent customer growth. The major factors contributing to the decline in utility margin were the $17.6 million swing in our regulatory share of higher gas costs, a $4.2 million decrease in regulatory adjustments for income taxes paid and a $1.6 million decrease in margin from industrial customers due to weaker economic conditions.

Our weather normalization mechanism offset residential and commercial margin gains by $15.3 million for the year ended December 31, 2008 based on weather that was 7 percent colder than average, compared to an offset increased residential and commercial margins of $2.5 million for the year ended December 31, 2007 based on weather that was 3 percent colder than average. Our decoupling mechanism offset $4.9 million of residential and commercial margin losses in 2008, after adjusting for price elasticity in the annual Oregon PGA filing, compared to a margin increase of $0.5 million in 2007.

2007 compared to 2006:

Total utility margin increased $24.6 million or 8 percent in 2007 compared to 2006 with residential and commercial customers contributing an additional $9.7 million to margin in 2007, including the effects of the weather normalization and decoupling mechanisms. The $1.0 million decrease in margin from industrial customers in 2007 was partially offset by a decrease in other margin adjustments from regulatory deferrals and amortizations and miscellaneous fees. Total utility volumes sold and delivered in 2007 were about the same as in 2006. An increase in our regulatory share of gas cost savings of $4.0 million and a regulatory adjustment related to income taxes paid of $6.0 million also contributed to the increase in margin (see Regulatory Adjustment for Income Taxes Paid, and Cost of Gas Sold, below).

Our weather normalization mechanism offset residential and commercial margin gains by $2.5 million for the year ended December 31, 2007 based on weather that was 3 percent colder than average, compared to an increase of $2.3 million in added margin for the year ended December 31, 2006 based on weather that was 4 percent warmer than average. The decoupling mechanism added $0.5 million to residential and commercial margin in 2007, after adjusting for price elasticity in the annual Oregon PGA filing, compared to a margin decrease of $2.6 million in 2006.

Table of Contents

The following table summarizes the composition of gas utility volumes and revenues for the years ended December 31, 2008, 2007 and 2006:

Thousands except degree day and customer data	2008	2007	2006	Favorable/(Unfavorable) 2008 vs. 2007	Favorable/(Unfavorable) 2007 vs. 2006
Utility volumes - therms:					
Residential sales	428,787	398,960	382,665	29,827	16,295
Commercial sales	265,531	249,659	242,683	15,872	6,976
Industrial - firm sales	47,340	52,340	66,971	(5,000)	(14,631)
Industrial - firm transportation	184,832	161,790	150,153	23,042	11,637
Industrial - interruptible sales	87,484	89,128	112,736	(1,644)	(23,608)
Industrial - interruptible transportation	246,777	263,092	237,441	(16,315)	25,651
Total utility volumes sold and delivered	1,260,751	1,214,969	1,192,649	45,782	22,320
Utility operating revenues-dollars:					
Residential sales	$ 566,840	$ 555,312	$ 536,468	$ 11,528	$ 18,844
Commercial sales	298,943	298,800	290,666	143	8,134
Industrial - firm sales	46,579	54,567	66,986	(7,988)	(12,419)
Industrial - firm transportation	6,370	5,927	4,901	443	1,026
Industrial - interruptible sales	68,978	74,876	93,107	(5,898)	(18,231)
Industrial - interruptible transportation	7,918	8,264	7,899	(346)	365
Regulatory adjustment for income taxes paid (1)	1,760	5,996		(4,236)	5,996
Other revenues	21,784	12,228	161	9,556	12,067
Total utility operating revenues	1,019,172	1,015,970	1,000,188	3,202	15,782
Cost of gas sold	656,504	639,094	648,081	(17,410)	8,987
Revenue taxes	25,072	25,001	24,840	(71)	(161)
Utility net operating revenues (utility margin)	$ 337,596	$ 351,875	$ 327,267	$ (14,279)	$ 24,608
Utility margin: (2)					
Residential sales	$ 224,683	$ 213,698	$ 204,951	$ 10,985	$ 8,747
Commercial sales	90,402	85,960	83,334	4,442	2,626
Industrial - sales and transportation	29,771	31,333	32,383	(1,562)	(1,050)
Miscellaneous revenues	6,381	4,966	4,333	1,415	633
Gain (loss) from gas cost incentive sharing	(5,505)	12,135	8,083	(17,640)	4,052
Other margin adjustments	436	(229)	(5,473)	665	5,244
Margin before regulatory adjustments	346,168	347,863	327,611	(1,695)	20,252
Weather normalization mechanism	(15,266)	(2,496)	2,282	(12,770)	(4,778)
Decoupling mechanism	4,934	512	(2,626)	4,422	3,138
Regulatory adjustment for income taxes paid (1)	1,760	5,996		(4,236)	5,996
Utility margin	$ 337,596	$ 351,875	$ 327,267	$ (14,279)	$ 24,608
Customers - end of period:					
Residential customers	599,285	589,676	575,116	9,609	14,560
Commercial customers	62,115	61,397	60,523	718	874
Industrial customers	941	939	945	2	(6)

Total number of customers - end of period	662,341	652,012	636,584	10,329	15,428
Actual degree days	4,576	4,374	4,089		
Percent colder (warmer) than average [3]	7%	3%	(4%)		

(1) Regulatory adjustment for income taxes paid is the result of the implementation of the utility regulation as described below under Regulatory Adjustment for Income Taxes Paid.

(2) Amounts reported as margin for each category of customers are net of demand charges and revenue taxes.

(3) Average weather represents the 25-year average degree days, as determined in our last Oregon general rate case.

49

Table of Contents

Residential and Commercial Sales

Residential and commercial sales are impacted by customer growth, seasonal weather patterns, energy prices, competition from other energy sources and economic conditions in our service areas. Typically, 80 percent or more of our 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 due to our weather normalization mechanism in Oregon where about 90 percent of our customers are served. Beginning in 2006, this mechanism became effective for the period from December 1 through May 15 of each heating season. Approximately 10 percent of our eligible Oregon customers have opted out of the mechanism. In Oregon, we also have a conservation decoupling mechanism that is intended to break the link between our earnings and the quantity of gas consumed by our customers, so that we do not have an incentive to encourage greater consumption contrary to customers energy conservation efforts. In Washington, where the remaining approximately 10 percent of our customers are served, we do not have a weather normalization or a conservation decoupling mechanism. As a result, we are not fully insulated from earnings volatility due to weather and conservation.

The primary factors that impact results of operations in the residential and commercial markets are customer growth, seasonal weather patterns, competition from other energy sources and economic conditions in our service territory.

2008 compared to 2007:

- operating revenues increased 1 percent due to a 7 percent increase in volumes, partially offset by lower customer rates of 8 to 10 percent over the first 10 months of 2008;
- volumes were 7 percent higher, primarily reflecting 1.6 percent customer growth and 5 percent colder weather; and
- margin was 2 percent higher, reflecting increased volumes from customer growth and from colder weather for customers not covered by weather normalization (see Cost of Gas Sold, below).

2007 compared to 2006:

- operating revenues increased 3 percent, primarily due to a 4 percent increase in volumes;
- volumes were 4 percent higher, primarily reflecting 2.4 percent customer growth and 7 percent colder weather; and
- margin before regulatory adjustments for weather normalization, decoupling and income taxes paid was 4 percent higher, reflecting increased volumes from customer growth and higher gas cost savings from our PGA incentive sharing mechanism in Oregon (see Cost of Gas Sold, below).

Industrial Sales and Transportation

Industrial operating revenues include the commodity cost component of gas sold under sales service but not to transportation service. Therefore, industrial customer switching between sales service and transportation service can cause swings in operating revenues but generally our margins are not affected because we do not mark up the cost of gas. As such, we believe margin is a better

Table of Contents

measure of performance for the industrial sector. The primary factors that impact results of operations in industrial sales and transportation markets are as follows:

2008 compared to 2007:

- operating revenues decreased $13.8 million, or 10 percent, due to a transfer of customer volumes from sales service to transportation and to lower sales rates during the first 10 months in 2008;
- volumes delivered to industrial customers increased 0.1 million therms, or less than 1 percent, reflecting a reduction in sales volumes of 6.6 million therms offset by an increase in transportation volumes of 6.7 million therms; and
- margin decreased $1.6 million, or 5 percent, reflecting a shift in margin from higher margins to lower margin rate schedules and from customers that reduced their usage due to the current economic environment, but this decrease was partially offset by a margin gain of $0.8 million from curtailment charges for use by a small number of industrial customers during cold weather.

2007 compared to 2006:

- operating revenue decreased $29.3 million, or 17 percent, due to customers transferring from sales service to transportation service where cost of gas is not a component in operating revenues;
- volumes delivered to industrial customers decreased 1.0 million therms, or less than 1 percent, reflecting a reduction in sales volumes of 38.2 million therms offset by an increase in transportation volumes of 37.3 million therms; and
- margin decreased 3 percent, reflecting higher volumes under lower margin special contracts.

Several large industrial customers transferred from sales service back to transportation service in 2008. High natural gas prices can result from time to time 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. In such cases, our tariff requires us to charge the incremental cost of gas supply incurred to serve those customers.

Regulatory Adjustment for Income Taxes Paid

The Oregon legislature passed legislation, effective January 1, 2006, to ensure that regulated utility operations do not collect in rates more money for income taxes than the utility actually pays to taxing authorities. Under this legislation, if we pay less in income taxes than we collect from our Oregon utility customers, or if our consolidated taxes paid are less than the taxes we collect from our Oregon utility customers, then we are required to record a refund due to our Oregon utility customers. Conversely, if we pay more income taxes than we actually collect from our Oregon utility customers, as set forth under our most recent general rate case, then we are required to record a surcharge due from our Oregon utility customers.

For the 2006 tax year, we filed to recover $1.7 million through a surcharge to our Oregon utility customers. This surcharge was primarily driven by higher income taxes paid on gains from gas cost savings from our PGA incentive sharing mechanism in 2006 and strong operating results. The OPUC

51

approved our filing, and we collected a total of $1.9 million, representing a surcharge of $1.7 million plus accrued interest of $0.2 million, from customers in June 2008. For the 2007 tax year, we filed to recover $5.5 million through a surcharge to our Oregon utility customers. We have reached an agreement in principle with OPUC Staff and other parties on that surcharge and are in the process of finalizing a stipulation and supporting documentation. We expect to collect a total of $6.4 million, representing a surcharge of $5.5 million plus accrued interest of $0.9 million. Again, this surcharge was primarily driven by higher income taxes paid on gains from gas cost savings from our PGA incentive mechanism in 2007. For the 2008 tax year, we anticipate that the difference between income taxes paid and the amounts collected in rates will be less than $100,000, and in accordance with the rules, we have not recorded any adjustment for this year. However, in 2008 we recognized a combined adjustment for the 2006 and 2007 tax years of $1.8 million, based on revised estimates of our 2006 and 2007 tax surcharges, representing $1.2 million plus accrued interest of $0.6 million.

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 $21.8 million in 2008, compared to $12.2 million in 2007 and $0.2 million in 2006.

2008 compared to 2007:

Other revenues in 2008 were $9.6 million higher than in 2007 primarily due to a $10.5 million refund to utility customers for the gas storage sharing mechanism revenues, partially offset by a $1.9 million surcharge for our rate adjustment for income taxes paid.

2007 compared to 2006:

Other revenues in 2007 were $12.1 million higher than in 2006 primarily due to a $3.1 million increase in deferrals under the decoupling mechanism (see Results of Operations Regulatory Matters Rate Mechanisms, above), a $6.1 million decrease in amortization expense related to the decoupling deferrals from prior periods, a $1.7 million increase in interstate gas storage credits to customers reflecting higher regulatory sharing of net income from storage operations and a decrease of $1.3 million in amortization expense related to demand side management deferrals.

Cost of Gas Sold

The cost of gas sold includes current gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use. Our regulated utility does not generally earn a profit or incur a loss on gas commodity purchases. The OPUC and the WUTC require the natural gas commodity cost to be billed to customers at the same cost incurred or expected to be incurred by the utility. However, under the PGA mechanism in Oregon, our net income is affected by differences between actual and expected purchased gas costs primarily due to market fluctuations and volatility affecting unhedged purchases (see Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, above). We use natural gas derivatives, primarily fixed-price commodity swaps, under the terms of our financial derivatives policies to help manage our exposure to rising gas prices. Gains and losses from financial hedge contracts are generally included in our PGA prices and normally do not impact net income as the hedges are usually 100 percent passed

through to customers in annual rate changes, subject to a regulatory prudency review. However, utility gas hedges entered into after the annual PGA filing in Oregon may impact net income to the extent of our share of any gain or loss under the PGA. In Washington, 100 percent of the actual gas costs, including hedge gains and losses, are passed through in customer rates (see Application of Critical Accounting Policies and Estimates Accounting for Derivative Instruments and Hedging Activities, and Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, above, and Note 11).

2008 compared to 2007:

- total cost of gas sold increased $17.4 million or 3 percent;
- the average cost of gas sold decreased 2 percent from 81 cents per therm in 2007 to 79 cents in 2008, primarily reflecting our 8 to 10 percent PGA rate decreases effective November 1, 2007 and our 14 to 21 percent increases effective November 1, 2008; and
- net gains of $35.1 million were realized from our financial hedges and included in cost of gas sold, compared to $42.0 million of net losses in 2007.

2007 compared to 2006:

- total cost of gas sold decreased $9.0 million or 1 percent;
- the average cost of gas sold remained at 81 cents per therm; and
- net losses of $42.0 million were realized from our financial hedges, compared to $20.0 million of net losses in 2006.

For the year ended December 31, 2008, our actual gas costs were higher than the gas costs embedded in rates, while during the same period in 2007 and 2006 our actual gas costs were significantly lower than gas costs embedded in rates. The effect on shareholders from the gas cost incentive sharing was a margin gain of $12.1 million and $8.1 million in 2007 and 2006, respectively, compared to a margin loss of $5.5 million in 2008. For a discussion of the change in our Oregon gas cost sharing incentive mechanism, effective November 1, 2008, see Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, above.

Business Segments Other than Utility Operations

Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility, asset optimization and Gill Ranch. In 2008, we earned $8.4 million, or 31 cents per share, from our gas storage business segment, after regulatory sharing and income taxes. This compares to net income of $8.5 million, or 32 cents per share, in 2007 and $6.0 million, or 21 cents per share, in 2006. Earnings in 2008 and 2007 were higher than 2006 primarily because of increased revenues from additional contract storage and higher margins from optimization services under a contract with an independent energy marketing company.

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

mechanism in Washington for pre-tax income derived from gas storage and optimization services. We are currently in the process of developing a second underground storage facility, Gill Ranch, and related pipeline near Fresno, California. Our Gill Ranch project is expected to serve the California and west coast market. See Note 2.

Other

Our other business segment consists of Financial Corporation, an equity investment in Palomar and other non-utility investments and business activities. Financial Corporation s equity balance as of December 31, 2008 and 2007 was $1.3 million and $1.4 million, respectively, and our equity balance in the proposed Palomar transmission pipeline was $14.2 million and $6.0 million, respectively. In 2008 and 2007, we sold the last of our non-core assets, resulting in after-tax gains of $1.1 million and $0.9 million, respectively. The remaining investment balance at Financial Corporation reflects a non-controlling interest in the Kelso Beaver pipeline. The current equity balance in Palomar reflects our investment to date in a proposed 217-mile transmission pipeline.

Net income from our other business segment for the years ended December 31, 2008, 2007 and 2006 was $2.4 million, $1.1 million and $0.8 million, respectively. The increase in 2008 compared to 2007 reflects the gain on sale of our investment in a Boeing 737-300 aircraft and income from our equity investment in Palomar. The increase in 2007 over 2006 reflects the sale of our limited partnership interest in two wind power electric generation projects in California. See Note 2.

Consolidated Operations

Operations and Maintenance

Operations and maintenance expenses decreased by $7.1 million in 2008, or 6 percent, compared to 2007. In 2007 operations and maintenance expense included additional costs for strategic initiatives. Operations and maintenance expense increased $5.9 million in 2007, or 5 percent, compared to 2006, also reflecting higher expenditures for strategic initiatives in 2007. The following summarizes the major factors that contributed to changes in operations and maintenance expense:

2008 compared to 2007:

- a $4.3 million decrease due to additional costs incurred in 2007 for strategic initiatives including maintenance projects, training and promotional and safety campaigns; and
- a $5.6 million decrease in employee compensation and benefit expense, primarily due to lower bonuses related to lower operating results which affected annual and long-term incentives.

Partially offsetting the above decreases were:

- a $2.0 million increase in costs related to serving a growing customer base and increased operating expenses during the December cold weather episode; and
- a $0.2 million, or 6 percent, increase in uncollectible expense reflecting higher revenues due to rate increases and sales volume increases. Delinquent account balances were $0.1 million higher than last year, compared to a $36.5 million, or 25 percent, increase in accounts receivable and unbilled revenues. Our bad debts as a percent of revenues remained consistent with 2007 at 0.3 percent.

Table of Contents

2007 compared to 2006:

- a $3.8 million increase in employee compensation and benefit expense, primarily due to bonuses related to improved financial and operating results on annual and long-term incentive plan performance goals;
- a $1.9 million increase in costs for maintenance projects and geo-hazard repairs;
- a $0.9 million increase in training, maintenance and telecommunication expenses related to the implementation of the first phase of a new integrated information system; and
- a $0.3 million increase in start up expenses for the Smart Energy program.

Partially offsetting the above increases was:

- a $1.5 million decrease in severance expenses.

General Taxes

General taxes, which are principally comprised of property and payroll taxes and regulatory fees, increased $1.4 million, or 5 percent, in 2008 compared to 2007, and increased $0.9 million, or 4 percent, in 2007 compared to 2006. The major factors that contributed to changes in general taxes are:

2008 compared to 2007:

- a $1.3 million increase in property taxes related to higher tax rates and increased utility plant balances.

2007 compared to 2006:

- a $0.4 million increase in property taxes related to a 3 percent increase in utility plant balances;
- a $0.3 million increase in regulatory fees based on higher gross operating revenue; and
- a $0.2 million increase in other taxes due to an increase in the annual fee to the Oregon Department of Energy.

We have been involved in litigation with the Oregon Department of Revenue (ODOR) over whether natural gas inventories and appliance inventories held for resale are required to be taxed as personal property. In November 2007, the Oregon Tax Court ruled in our favor stating that these inventories were exempt from property tax. However, the ODOR appealed the judgment to the Oregon Supreme Court in August 2008. If we are successful in this litigation, we would be entitled to a refund of over $5.0 million for property taxes paid on inventories beginning with the 2002-2003 tax year, plus accrued interest. Due to the uncertain outcome of the proceeding, we have not recorded the recovery of property taxes paid on gas inventories or appliance inventories to recognize the potential gain contingency.

Table of Contents

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, except percentages	2008	2007	2006
Plant and property:			
Utility plant:			
Depreciable	$ 2,101,900	$ 2,013,191	$ 1,925,837
Non-depreciable, including construction work in progress	41,088	38,970	37,661
	2,142,988	2,052,161	1,963,498
Non-utility property:			
Depreciable	62,882	56,444	36,952
Non-depreciable, including construction work in progress	11,624	10,705	5,700
	74,506	67,149	42,652
Total plant and property	$ 2,217,494	$ 2,119,310	$ 2,006,150
Depreciation and amortization:			
Utility plant	$ 70,691	$ 67,410	$ 63,552
Non-utility property	1,468	933	883
Total depreciation and amortization expense	$ 72,159	$ 68,343	$ 64,435
Average depreciation rate - utility	3.4%	3.4%	3.4%
Average depreciation rate - non-utility	2.5%	2.1%	2.5%

Total depreciation and amortization expense increased by $3.8 million, or 6 percent, in 2008 and by $3.9 million, or 6 percent, in 2007. 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). New depreciation rates were approved by the OPUC and WUTC, effective January 1, 2009 (see Regulatory Matters Rate Mechanisms Depreciation Study, above).

Other Income and Expense Net

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

Thousands	2008	2007	2006
Gains from company-owned life insurance	$ 2,190	$ 1,939	$ 2,609
Interest income	250	537	363
Income from equity investments	667	130	191
Net interest on deferred regulatory accounts	552	84	(177)
Gain on sale of investments	1,737	1,544	-
Other	(1,650)	(2,789)	(852)

Total other income and expense - net	$ 3,746	$ 1,445	$ 2,134

2008 compared to 2007:

Other income and expense net increased by $2.3 million in 2008 over 2007. The increase was primarily due to an increase of $1.1 million in other non-operating income (expense), reflecting the

56

Table of Contents

additional start-up expenses in 2007 for business development and other strategic initiatives, and by a $0.2 million increase from gain on sale of investments, reflecting the gains on sales of the aircraft in 2008 and the two wind power electric generation projects in 2007, and a $0.5 million increase in income from equity investments, primarily related to Palomar.

2007 compared to 2006:

Other income and expense net declined by $0.7 million in 2007 over 2006. The decline was primarily due to a decrease of $0.7 million in gains from company-owned life insurance, reflecting lower policy benefits realized during 2007, and a net increase of $1.9 million in other non-operating expenses, reflecting expenses for business development and other strategic initiatives. These negative changes were partially offset by an increase in earnings from equity investments of Financial Corporation of $1.5 million, reflecting the gain on sale of its limited partnership interests in two wind power electric generation projects, and an increase of $0.3 million in net interest charges on deferred regulatory accounts, reflecting lower net credit balances outstanding in these accounts.

Interest Charges Net of Amounts Capitalized

Interest charges net of amounts capitalized in 2008 decreased by $0.2 million, or less than 1 percent, compared to 2007, reflecting lower balances on long-term debt outstanding due to the redemption of $5 million of medium-term notes (MTNs) in July 2008, with increased costs due to higher short-term debt balances offset by lower interest rates on short-term debt. In 2007, interest charges net of amounts capitalized was $1.4 million, or 4 percent, lower than in 2006, reflecting lower balances on long-term debt outstanding due to the redemption of $20 million of MTNs in March 2007 and $9.5 million of MTNs in May 2007. The average interest crediting rate for the allowance for funds used during construction, comprised of short-term and long-term borrowing rates, as appropriate, was 3.6 percent in 2008, 5.4 percent in 2007 and 4.7 percent in 2006.

Income Tax Expense

The decrease in income tax expense of $3.4 million or 8 percent in 2008, compared to 2007 was primarily due to lower consolidated earnings and a slightly lower effective tax rate of 36.9 percent in 2008 compared to 37.2 percent in 2007. The decrease in our effective tax rate was primarily the result of a higher non-taxable gain on company-owned life insurance. Income tax expense increased by $7.8 million or 22 percent in 2007, as compared to total income tax expense of $36.2 million in 2006, and the effective tax rate increased slightly from an effective rate of 36.4 percent in 2006. For more information on our income taxes, including a reconciliation between the statutory federal income tax rate and the effective rate, see Note 1 and Note 8.

Financial Condition

Capital Structure

Our goal is to maintain a strong consolidated capital structure, generally consisting 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 fund long-term debt redemption requirements and short-term commercial paper maturities (see Liquidity and Capital Resources, below, and Notes 5 and 6). Achieving the target capital structure and maintaining sufficient liquidity to meet operating

Table of Contents

requirements are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure was as follows:

December 31,	2008	2007	2006
Common stock equity	45.3%	47.4%	48.1%
Long-term debt	36.8%	40.8%	41.5%
Short-term debt, including current maturities of long-term debt	17.9%	11.8%	10.4%
Total	100.0%	100.0%	100.0%

Liquidity and Capital Resources

At December 31, 2008, we had $6.9 million of cash and cash equivalents compared to $6.1 million at December 31, 2007. Short-term liquidity is provided by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, unsecured credit facilities, including multi-year commitments which are primarily used to back-up commercial paper (see Credit Agreement, below), an ability to borrow from cash surrender value in company-owned life insurance policies, and proceeds from the sale of long-term debt. We use long-term debt proceeds to finance capital expenditures and refinance maturing short-term or long-term debt.

Our senior long-term debt ratings are AA- and A2 from S&P and Moody s, respectively, while our short-term debt ratings are A-1+ and P-1 from S&P and Moody s, respectively. The capital markets, including the commercial paper market, have experienced significant volatility and tight credit conditions in recent months, as reflected by increased spreads and limited access to new financing. As a result of these market conditions, we delayed a planned fourth quarter 2008 debt issuance until the first quarter of 2009. In lieu of the delayed debt issuance, we entered into two $15 million bilateral bank lines of credit with maturities of one and three months, and borrowed from corporate-owned life insurance policies to provide added liquidity. With our current debt ratings we have been able to issue commercial paper notes at attractive rates and have not had to borrow from our $250 million back-up facility. In the event that we are not able to issue commercial paper or other debt instruments due to market conditions, we expect that our liquidity needs can be met by using cash balances or drawing upon our committed credit facility (see Credit Agreements, below). We also have a universal shelf registration statement filed with the Securities and Exchange Commission for the issuance of secured and unsecured debt or equity securities, market conditions permitting.

In the event that our senior secured long-term debt credit ratings are downgraded below investment grade, our counterparties under derivative contracts could require us to post cash, a letter of credit or other form of collateral, which could expose us to additional costs and may trigger significant increases in draws from our borrowing facilities.

Based on our current credit ratings, our experience with issuing commercial paper, our current cash reserves, the availability and size of our committed credit facilities and our ability to issue long-term debt and equity securities under the universal shelf registration statement, we believe our liquidity is sufficient to meet 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 was first issued to the public in 1951. Annual common dividend payments per share, adjusted for stock splits, have increased each year since 1956. The amount and timing of dividends payable on our common

Table of Contents

stock is within the sole discretion of our Board of Directors. Our Board of Directors expects to continue paying cash dividends on common stock on a quarterly basis. However, the declarations and amount 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 at December 31, 2008 by maturity and type of obligation.

	Payments Due in Years Ending December 31,						
Thousands	2009	2010	2011	2012	2013	Thereafter	Total
Commercial paper	$ 248,000	$ -	$ -	$ -	$ -	$ -	$ 248,000
Long-term debt maturities	-	35,000	10,000	40,000	-	427,000	512,000
Interest on long-term debt	33,417	33,406	30,858	28,536	27,625	285,432	439,274
Postretirement benefit payments[(1)]	26,839	19,126	19,556	20,394	21,571	116,388	223,874
Capital leases	599	461	163	21	-	-	1,244
Operating leases	4,129	4,127	4,080	4,230	4,268	26,501	47,335
Gas purchase contracts[(2)]	229,804	89,079	34,835	21,277	21,277	17,731	414,003
Gas pipeline commitments	80,670	61,114	64,175	49,067	41,602	87,826	384,454
Other purchase commitments	53,081	5,154	762	-	-	-	58,997
Total	$ 676,539	$ 247,467	$ 164,429	$ 163,525	$ 116,343	$ 960,878	$ 2,329,181

(1) The majority of postretirement benefit payment obligations are related to our qualified defined benefit pension plans, which are funded by plan assets and future cash contributions. See Note 7.

(2) All gas purchase contracts use price formulas tied to monthly index prices. Commitment amounts are based on index prices at December 31, 2008.

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 one long-term debt issue have a put option that, if exercised, would require the repurchase of up to $20 million principal amount in 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 this long-term debt issue with a put option is 6.65 percent.

In February 2008, we extended the term of an agreement with Northwest Pipeline for approximately 350,000 therms per day of firm transportation capacity from the U.S. Rocky Mountain region through 2044. Also in February 2008, we executed an agreement with a third party to take assignment of their firm transportation contract starting no earlier than 2012 and no later than 2017, with the term extending through 2046. This contract consists of 120,000 therms per day on Northwest Pipeline from the U.S. Rocky Mountain region.

Approximately 700 of our utility employees are members of the Office and Professional Employees International Union, Local No. 11. These employees are covered by a labor agreement (Joint Accord) with respect to wages, benefits and working conditions. This Joint Accord will expire on May 31, 2009. Each party has served notice of intent to negotiate the terms of an agreement prior to the May 31, 2009 expiration date.

Commercial Paper

Our primary source of short-term liquidity is from internal cash flows and the sale of commercial paper notes payable. 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 be used to temporarily fund capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by one or more unsecured revolving credit facilities (see Credit Agreement, below and Note 6). Our commercial paper program did not experience any liquidity disruptions as a result of the recent credit problems that affected issuers of asset-backed commercial paper and certain other commercial paper programs. At December 31, 2008 and 2007 we had commercial paper outstanding of $248.0 million and $143.1 million, respectively (see Note 6). This year s outstanding balances were higher than last year primarily due to gas cost deferrals associated with higher gas purchases, higher balances in gas inventories and accounts receivable, commodity hedge payments, and delaying the issuance of long-term debt.

Credit Agreements

We have a syndicated line of credit for unsecured revolving loans totaling $250 million available and committed for a term expiring on May 31, 2012, with $210 million of that commitment amount extended through May 31, 2013. Additionally, we entered into two committed bilateral bank lines of credit totaling $30 million in November 2008, of which $15 million expired December 31, 2008 and $15 million expired February 27, 2009. The lenders under our syndicated and bilateral credit agreements are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2008 as follows:

Lender rating, by category	Amount Committed (in $000 s)
AAA/Aaa	$ 135,000
AA/Aa	45,000
A/A	85,000
BBB/Baa	-
Total	$ 265,000

Based on recent conditions in the credit markets, it is possible that one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency. However, based on our current assessment of the lenders creditworthiness, including a review of capital ratios, credit default swap spreads and credit ratings, we believe the risk of lender default is minimal.

Pursuant to the terms of our credit agreement for the syndicated line of credit, we may request maturity extensions for additional one-year periods subject to lender approval. We extended commitments with six of the seven lenders under the syndicated credit agreement, with commitments totaling $210 million, to May 31, 2013. The credit agreement also allows us to request increases in the total commitment amount from time to time, up to a maximum amount of $400 million, and to replace any lenders who decline to extend the terms of the credit agreement. The credit agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. Any principal and unpaid interest owed on borrowings under the credit agreement are due and payable on or before the expiration date. There were no outstanding balances under this credit agreement at December 31, 2008 and 2007. The credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2008 and 2007, with our consolidated indebtedness to total capitalization ratios of 54.7 percent, and 52.7 percent, respectively.

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

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	Negative	Stable

Both rating agencies have assigned investment grade credit ratings to NW Natural. These credit ratings 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 NW Natural securities. Each rating should be evaluated independently of any other rating. During the fourth quarter of 2008, our ratings outlook was changed from stable to negative by S&P and from positive to stable by Moody s.

Redemptions of Long-Term Debt

We redeemed MTNs during 2008, 2007 and 2006 as follows:

Thousands	Redeemed in 2008	Redeemed in 2007	Redeemed in 2006
Medium-Term Notes			
6.05% Series B due 2006	$ -	$ -	$ 8,000
6.31% Series B due 2007	-	20,000	-
6.80% Series B due 2007	-	9,500	-
6.50% Series B due 2008	5,000	-	-

Table of Contents

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 2008, cash flow from net income and operating activity adjustments, excluding working capital changes, decreased $37.9 million compared to 2007. Working capital changes in 2008 decreased cash flow by $111.0 million compared to 2007. The majority of these working capital changes, particularly those related to accounts receivable, unbilled revenues inventories, income taxes receivable and accounts payable, will reverse over the next six months reflecting changes in seasonal working capital. The overall change in cash flow from operating activities in 2008 compared to 2007 was a decrease of $148.9 million. The significant factors contributing to the cash flow changes between 2008 and 2007 are as follows:

2008 compared to 2007:

- an increase in cash flow of $55.4 million in deferred income taxes and investment tax credits primarily from additional accelerated depreciation and a net operating loss (see Note 8);
- a decrease in cash flows of $84.0 million in deferred gas costs, $30.4 million in accounts payable and a $14.3 million in inventories, primarily due to the higher gas cost prices in 2008 compared to 2007;
- a decrease in cash flow of $20.8 million in income taxes receivable primarily due to bonus depreciation and an estimate for a future pension contribution, for which we saw an increase in deferred income taxes; and
- a decrease in cash flow of $58.5 million in accounts receivable and accrued unbilled revenue due to the colder weather in December 2008 and our November 1, 2008 rate increase (see Results of Operations Regulatory Matters Rate Mechanisms Purchased Gas Adjustment, above).

In December 2008, we filed an application for a change in tax accounting method in connection with routine repairs and maintenance of gas pipeline that are currently being capitalized and depreciated. We anticipate that the Internal Revenue Service (IRS) will consent to this change during the first quarter of 2009. If consented to by the IRS, then we expect to claim a deduction and record current tax benefits that will result in a cash refund of taxes paid. If approved, we estimate the tax refund amount in 2009 for prior years taxes paid to be in excess of $15 million related to the routine repairs and maintenance.

In 2007, cash flow from net income and operating activity adjustments, excluding working capital changes, increased by $23.0 million, primarily due an increase in cash collections from deferred gas costs and improved operating results. Working capital changes in 2007 increased cash flow by $12.1 million. The overall change in cash flow from operations in 2007 was an increase of $35.1 million compared to 2006. The significant factors contributing to the cash flow changes between 2007 and 2006 are as follows:

2007 compared to 2006:

- an increase in cash of $11.2 million in deferred income taxes and investment tax credits related to a smaller reduction in 2007 than 2006;

- an increase in cash of $17.9 million in deferred gas costs and an increase in cash of $27.5 million in accounts payable, reflecting deferral activity between the two years with respect to purchased gas cost savings and off-system gas sales under our PGA;
- a decrease in cash of $17.5 million due to the change in deferred regulatory and other costs;
- an increase in cash of $25.8 million in accounts receivable and accrued unbilled revenue, due to decreased rates in 2007 and weather that was warmer at the end of the year;
- a decrease in cash of $13.2 million in income taxes receivable resulting from income tax refunds received during 2006; and
- a decrease in cash of $16.7 million in accrued interest and taxes due to higher cash payments in 2007.

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 2008 totaled $109.8 million, down from $117.5 million in 2007. Cash requirements for the acquisition and construction of utility plant were $96.6 million in 2008, up slightly from $93.8 million in 2007. Cash requirements for investments in non-utility property were $7.4 million in 2008, primarily related to investments in Gill Ranch, compared to $24.4 million in 2007, primarily due to investments made related to the Mist gas storage expansion. Cash used in other investing activities in 2008 totaled $5.8 million compared to cash collected of $0.7 million in 2007. The change in 2008 is primarily due to a $7.5 million investment in the Palomar project and a $5.0 million restricted cash balance in Gill Ranch, partially offset by $6.8 million of proceeds received from the sale of our investment in a Boeing 737-300 aircraft.

Cash requirements for investing activities in 2007 totaled $117.5 million, up from $90.6 million in 2006. Cash requirements for the acquisition and construction of utility plant were $93.8 million in 2007, down slightly from $95.3 million in 2006. Cash requirements for investments in non-utility property increased to $24.4 million in 2007, compared to $1.8 million in 2006, primarily related to investments in Mist gas storage, Gill Ranch and Palomar.

In 2009, utility capital expenditures are estimated to be between $100 and $110 million, and non-utility capital investments are expected to be between $50 and $70 million for business development projects that are currently in process (see 2009 Outlook, above).

Over the five-year period 2009 through 2013, utility construction expenditures are estimated at between $450 and $500 million. The estimated level of capital expenditures over the next five years reflects continued customer growth, gas storage development at Mist, 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.

Financing Activities

Cash provided by financing activities in 2008 totaled $75.9 million, as compared to cash used of $65.8 million in 2007. Factors contributing to the $141.7 million net increase in cash include share repurchases of $44.6 million in 2007 compared to no repurchases in 2008, long-term debt retired of $5.0 million in 2008 compared to $29.5 million in 2007, and an increase in short-term debt balances of $74.7 million in 2008, including borrowings from the cash surrender value in company-owned life insurance policies, compared to 2007.

Cash used in financing activities in 2007 totaled $65.8 million, as compared to $59.4 million in 2006. Factors contributing to the $6.4 million net increase in cash used include an increase in share repurchases of $28.7 million, an increase in long-term debt retired of $21.5 million, and a reduction in long-term debt issuances of $25.0 million, offset by an increase in cash from the change in short-term debt balances of $69.6 million in 2007 compared to 2006.

In October 2007, we entered into a forward-starting interest rate swap with a notional principal amount of $50 million. This fixed-rate forward-starting swap is intended to mitigate a substantial portion of the interest rate exposure associated with our anticipated issuance of MTNs in the first quarter of 2009 when we would expect to cash settle this contract. The associated gain or loss on settlement will be recorded as a regulatory asset or liability and amortized in accordance with regulatory requirements. We did not issue any new long-term debt during 2007 or 2008.

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

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. In 2006 that program was modified to 2.6 million shares and $85 million in value, and the program was further modified in 2007 to authorize the repurchase of up to 2.8 million shares or up to $100 million and was extended through May 2009. The purchases are made in the open market or through privately negotiated transactions. No repurchases were made in 2008. Repurchases in 2007 totaled 963,428 shares or $44.2 million; and in 2006 totaled 395,500 shares or $16.0 million. Since the program s inception, we have repurchased an aggregate 2.1 million shares of common stock at a total cost of $83.3 million (see Part II, Item 5, Market for the Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities, above).

In 2008, we produced negative free cash flow of $115.3 million, compared to free cash flow of $27.5 million in 2007 and $19.7 million in 2006. Free cash flow is the amount of cash remaining 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)	2008	2007	2006
Cash provided by operating activities	$ 34,721	$ 183,640	$ 148,566
Cash used in investing activities	(109,825)	(117,479)	(90,567)
Cash dividend payments on common stock	(40,178)	(38,613)	(38,298)
Free cash flow	$ (115,282)	$ 27,548	$ 19,701

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

64

Table of Contents

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 (see Application of Critical Accounting Policies and Estimates Accounting for Pensions, above). Pension costs for our two qualified defined benefit plans, which are allocated between operations and maintenance expense and capital accounts based on employee payroll distributions, totaled $4.3 million in 2008, a decrease of $2.4 million over 2007.

The fair market value of the assets in these two plans decreased to $163.1 million at December 31, 2008 down from $241.4 million at December 31, 2007. The decrease was due to a negative return on plan assets of $63.3 million and benefit payments of $15.0 million net of contributions.

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. The Pension Protection Act of 2006 (the Act) established new funding requirements for defined benefit plans. The Act establishes a 100 percent funding target for plan years beginning after December 31, 2008. However, a delayed effective date of 2011 may apply if the pension plan meets the funding targets of 92 percent in 2008, 94 percent in 2009 and 96 percent in 2010. Our qualified defined benefit pension plans are currently underfunded by $98.4 million at December 31, 2008, and we expect to make at least the minimum contribution required pursuant to the Act, which is currently estimated at $8 million. We plan to make additional contributions during 2009, which could bring our total contributions in 2009 up to $40 million. We would need to make a total contribution of at least $17 million during 2009 to avoid any restrictions on benefit payments. For more information, see Note 7.

Ratios of Earnings to Fixed Charges

For the years ended December 31, 2008, 2007 and 2006, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 3.76, 3.92 and 3.40, 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 (see Application of Critical Accounting Policies and Estimates Contingencies, above). At December 31, 2008, a cumulative $66.1 million in environmental costs was recorded as a regulatory asset, consisting of $30.1 million of costs paid to-date, $30.0 million for additional environmental accruals for costs expected to be paid in the future and accrued regulatory interest of $6.0 million. If it is determined that both the insurance recovery and future customer rate recovery of such costs was 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.

Table of Contents

New Accounting Pronouncements

For a description of recent accounting pronouncements that may have an impact on our financial condition, results of operations or cash flows, see Note 1.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Supply Risk

We enter into spot, short-term and long-term natural gas supply contracts, along with associated pipeline transportation contracts, to manage our commodity supply risk. Historically, we have arranged for physical delivery of an adequate supply of gas, including gas in storage facilities, to meet the expected requirements of our core utility customers. Our gas purchase contracts are primarily index-based and subject to monthly re-pricing, a strategy that is intended to reflect market price trends during the upcoming year. Our PGA mechanisms in Oregon and Washington provide for the recovery from customers of actual commodity costs, except that, for Oregon customers, we currently absorb 20 percent of the higher cost of gas sold, or retain 20 percent of the lower cost, in either case as compared to the annual PGA price built into customer rates.

Commodity Price Risk

Natural gas commodity prices are subject to fluctuations due to unpredictable factors including weather, pipeline transportation congestion, potential market speculation and other factors that affect short-term supply and demand. Commodity-price financial swap and option contracts (financial hedge contracts) are used to convert certain natural gas supply contracts from floating prices to fixed or capped prices. These financial hedge contracts are generally included in our annual PGA filing for recovery, subject to a regulatory prudence review. At December 31, 2008 and 2007, notional amounts under these financial hedge contracts totaled $393.0 million and $287.6 million, respectively. If all of the commodity-based financial hedge contracts had been settled on December 31, 2008, a loss of about $139.2 million would have been realized and recorded to a deferred regulatory account (see Note 11). We monitor the liquidity of our financial hedge contracts. Based on the existing open interest in the contracts held, we believe existing contracts to be liquid. All of our financial hedge contracts settle by or are extendible to October 31, 2010. The $139.2 million unrealized loss is an estimate of future cash flows based on forward market prices that are expected to be paid as follows: $130.3 million in the next 12-month period, and $8.9 million in the following 12-month period. The amount realized will change based on market prices at the time contract settlements are fixed.

Natural gas commodity prices early in the third quarter of 2008 were higher than prices embedded in the corresponding PGA for unhedged purchases. To the extent that we purchase gas volumes where the price is not hedged and the current market prices are above those embedded in rates for current customer consumption (i.e. not for storage injections), our earnings are negatively impacted because either 10 to 20 percent of any difference between the actual purchase gas costs and the gas costs embedded in Oregon rates are recognized in current income. In 2008, we recognized a loss of $5.5 million due to higher gas prices.

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 primarily managed through the issuance of fixed-rate debt with varying maturities. We may also enter into financial derivative instruments, including interest rate swaps, options and other hedging instruments, to manage and mitigate interest rate exposure. During the fourth quarter of 2007, we entered into a forward starting interest rate swap with a notional amount of $50 million to hedge the interest rate on our next long-term debt issuance, which was expected to occur in the latter part of 2008. However, due to credit market conditions, the swap was extended to the second quarter of 2009. This swap is with an A+/Aa2 rated counterparty and qualifies as a cash flow hedge 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). The mark-to-market unrealized loss at December 31, 2008 related to this interest rate swap was $11.9 million.

Holders of certain long-term debt have put options that, if exercised, would accelerate maturities by $20 million in 2009 (see Note 5).

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 purchases of natural gas from Canadian suppliers. At December 31, 2008 and 2007, notional amounts under foreign currency forward contracts totaled $5.2 million and $6.1 million, respectively. As of December 31, 2008, no foreign currency forward contracts were outstanding with a maturity date after November 30, 2009. If all of the foreign currency forward contracts had been settled on December 31, 2008, a loss of $0.4 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 at liquid exchange points. We evaluate and 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 tied to liquid exchange points, 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 at December 31, 2008, our credit exposure relating to commodity hedge contracts reflected an amount we owed of $130.3 million to our finance derivative counterparties. Our financial derivatives policy requires counterparties to have a minimum investment-grade credit rating at the time the derivative instrument is entered into, and specific limits on the contract amount and duration based on each counterparty s credit rating. Some counterparties were recently downgraded but continue to maintain investment grade ratings (see table below). Due to current market conditions and credit concerns, we

67

continue to enforce strong credit requirements. We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require letters of credit or guarantees as circumstances warrant. Our actual derivative credit exposure, which reflects amounts that financial derivative counterparties owe to us, is under contracts that expire or are expected to settle on or before October 31, 2010.

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 the S&P or Moody s rating or a middle rating if the entity is split-rated with more than one rating level difference:

	Financial Derivative Position by Credit Rating Unrealized Fair Value Gain (Loss)	
Thousands	Dec. 31, 2008	Dec. 31, 2007
AAA/Aaa	$ (16,827)	$ (309)
AA/Aa	(122,287)	(13,941)
A/A	(12,006)	123
BBB/Baa	-	-
Total	$ (151,120)	$ (14,127)

To mitigate the credit risk of financial derivatives we have master netting arrangements with our counterparties that provide for making or receiving net cash settlements. Generally, transactions of the same type in the same currency that have a settlement on the same day with a single counterparty are netted and a single payment is delivered or received depending on which party is due funds.

Additionally we have master contracts in place with each of our derivative counterparties that include provisions for posting or calling for collateral. Generally we can obtain cash or marketable securities as collateral with one day s notice. We use various collateral management strategies to reduce liquidity risk. The collateral provisions vary by counterparty but are not expected to result in the significant posting of collateral, if any. We have performed stress tests on the portfolio and concluded that the liquidity risk from collateral calls is not material. Our derivative credit exposure is primarily with investment grade counterparties rated AA-/Aa3 or higher. Contracts are diversified across counterparties to reduce credit and liquidity risk.

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 gas usage based on 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, 2008, less than 10 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.

Table of Contents

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.

Table of Contents

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 and dispositions 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 or fraud. 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, 2008. In making this assessment, management used the criteria 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, 2008.

The effectiveness of internal control over financial reporting as of December 31, 2008 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in this annual report.

/s/ Gregg S. Kantor

Gregg S. Kantor

President and Chief Executive Officer

/s/ David H. Anderson

David H. Anderson

Senior Vice President and Chief Financial Officer

February 27, 2009

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of

Northwest Natural Gas Company:

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, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 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. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management s Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for fair value measurements in 2008. As discussed in Note 7 to the consolidated financial statements, the Company changed the manner in which it accounts for defined benefit pension and other postretirement plans effective December 31, 2006.

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 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.

/s/ PricewaterhouseCoopers LLP

Portland, Oregon

February 27, 2009

Table of Contents

NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME

Thousands, except per share amounts (year ended December 31)	2008	2007	2006
Operating revenues:			
Gross operating revenues	$ 1,037,855	$ 1,033,193	$ 1,013,172
Less: Cost of sales	656,568	639,150	648,156
Revenue taxes	25,072	25,001	24,840
Net operating revenues	356,215	369,042	340,176
Operating expenses:			
Operations and maintenance	113,360	120,488	114,560
General taxes	26,660	25,288	24,419
Depreciation and amortization	72,159	68,343	64,435
Total operating expenses	212,179	214,119	203,414
Income from operations	144,036	154,923	136,762
Other income and expense - net	3,746	1,445	2,134
Interest charges - net of amounts capitalized	37,579	37,811	39,247
Income before income taxes	110,203	118,557	99,649
Income tax expense	40,678	44,060	36,234
Net income	$ 69,525	$ 74,497	$ 63,415
Average common shares outstanding:			
Basic	26,438	26,821	27,540
Diluted	26,594	26,995	27,657
Earnings per share of common stock:			
Basic	$ 2.63	$ 2.78	$ 2.30
Diluted	$ 2.61	$ 2.76	$ 2.29

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2008	2007
Assets:		
Plant and property:		
Utility plant	$ 2,142,988	$ 2,052,161
Less accumulated depreciation	659,123	615,533
Utility plant - net	1,483,865	1,436,628
Non-utility property	74,506	67,149
Less accumulated depreciation and amortization	9,314	7,904
Non-utility property - net	65,192	59,245
Total plant and property	1,549,057	1,495,873
Current assets:		
Cash and cash equivalents	6,916	6,107
Accounts receivable	81,288	69,442
Accrued unbilled revenue	102,688	78,004
Allowance for uncollectible accounts	(2,927)	(2,890)
Regulatory assets	147,319	17,598
Fair value of non-trading derivatives	4,592	2,903
Inventories:		
Gas	86,134	71,079
Materials and supplies	9,933	8,865
Income taxes receivable	20,811	-
Prepayments and other current assets	24,216	25,569
Total current assets	480,970	276,677
Investments, deferred charges and other assets:		
Regulatory assets	288,470	175,938
Fair value of non-trading derivatives	146	324
Other investments	54,132	54,070
Other	5,377	11,179
Total investments, deferred charges and other assets	348,125	241,511
Total assets	$ 2,378,152	$ 2,014,061

See Notes to Consolidated Financial Statements.

Table of Contents

NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2008	2007
Capitalization and liabilities:		
Capitalization:		
Common stock	$ 336,754	$ 331,595
Earnings invested in the business	296,005	266,658
Accumulated other comprehensive income (loss)	(4,386)	(3,502)
Total common stock equity	628,373	594,751
Long-term debt	512,000	512,000
Total capitalization	1,140,373	1,106,751
Current liabilities:		
Notes payable	248,000	143,100
Long-term debt due within one year	-	5,000
Accounts payable	94,422	119,731
Taxes accrued	12,455	13,137
Interest accrued	2,785	2,827
Regulatory liabilities	20,456	61,326
Fair value of non-trading derivatives	136,735	14,829
Other current and accrued liabilities	36,467	29,794
Total current liabilities	551,320	389,744
Deferred credits and other liabilities:		
Deferred income taxes and investment tax credits	257,831	206,340
Regulatory liabilities	228,157	213,764
Pension and other postretirement benefit liabilities	138,229	41,619
Fair value of non-trading derivatives	21,646	3,758
Other	40,596	52,085
Total deferred credits and other liabilities	686,459	517,566
Commitments and contingencies (see Note 12)	-	-
Total capitalization and liabilities	$ 2,378,152	$ 2,014,061

See Notes to Consolidated Financial Statements.

Table of Contents

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, 2005	$ 383,805	$ 205,687	$ (650)	$ (1,911)	$ 586,931	
Net Income	-	63,415	-	-	63,415	$ 63,415
Minimum pension liability adjustment, net of $52 of tax	-	-	-	(81)	(81)	(81)
Change in non-qualified employee benefit plan liability, net of $232 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
Net Income	-	74,497	-	-	74,497	$ 74,497
Change in unrealized loss from price risk management activities	-	-	-	(41)	(41)	(41)
Change in non-qualified employee benefit plan liability, net of $487 of tax	-	-	-	(1,232)	(1,232)	(1,232)
Amortization of non-qualified employee benefit plan liability, net of ($81) of tax	-	-	-	127	127	127
Restricted stock amortizations	285	-	-	-	285	
Dividends paid on common stock	-	(38,613)	-	-	(38,613)	
Tax benefits from employee stock option plan	536	-	-	-	536	
Stock-based compensation	2,094	-	-	-	2,094	
Issuance of common stock	2,180	-	-	-	2,180	
Common stock repurchased	(44,627)	-	-	-	(44,627)	
Balance at Dec. 31, 2007	331,595	266,658	-	(3,502)	594,751	$ 73,351
Net Income	-	69,525	-	-	69,525	$ 69,525
Change in unrealized loss from price risk management activities	-	-	-	41	41	41
Change in non-qualified employee benefit plan liability, net of $731 of tax	-	-	-	(1,145)	(1,145)	(1,145)
Amortization of non-qualified employee benefit plan liability, net of ($86) of tax	-	-	-	220	220	220
Restricted stock amortizations	275	-	-	-	275	

Dividends paid on common stock	-	(40,178)	-	-	(40,178)	
Tax benefits from employee stock option plan	282	-	-	-	282	
Stock-based compensation	1,523	-	-	-	1,523	
Issuance of common stock	3,079	-	-	-	3,079	
Balance at Dec. 31, 2008	$ 336,754	$ 296,005	$ -	$ (4,386)	$ 628,373	$ 68,641

See Notes to Consolidated Financial Statements.

75

Table of Contents

NORTHWEST NATURAL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

Thousands (year ended December 31)	2008	2007	2006
Operating activities:			
Net income	$ 69,525	$ 74,497	$ 63,415
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	72,159	68,343	64,435
Deferred income taxes and investment tax credits	50,192	(5,252)	(16,440)
Undistributed gains from equity investments	(667)	(130)	(191)
Deferred gas costs - net	(45,291)	38,665	20,752
Gain on sale of non-utility investments	(1,737)	(1,544)	(495)
Income from life insurance investments	(2,190)	(1,939)	(2,609)
Non-cash expenses related to qualified defined benefit pension plans	2,855	4,387	5,500
Deferred environmental expenditures	(8,179)	(8,842)	(6,675)
Deferred regulatory costs and other	(9,347)	(2,940)	14,533
Changes in working capital:			
Accounts receivable and accrued unbilled revenue - net	(36,493)	22,029	(3,722)
Inventories of gas, materials and supplies	(16,123)	(1,816)	8,033
Income taxes receivable	(20,811)	-	13,234
Prepayments and other current assets	363	(6,528)	2,952
Accounts payable	(24,540)	5,841	(21,708)
Accrued interest and taxes	(724)	(8,190)	8,511
Other current and accrued liabilities	5,729	7,059	(959)
Cash provided by operating activities	34,721	183,640	148,566
Investing activities:			
Investment in utility plant	(96,582)	(93,785)	(95,307)
Investment in non-utility property	(7,416)	(24,442)	(1,773)
Proceeds from sale of non-utility investments	7,531	2,628	2,517
Proceeds from life insurance	208	881	4,009
Contributions to non-utility equity investments	(7,450)	(5,413)	-
Other	(6,116)	2,652	(13)
Cash used in investing activities	(109,825)	(117,479)	(90,567)
Financing activities:			
Common stock issued, net of expenses	2,310	2,180	3,913
Common stock repurchased	-	(44,627)	(15,971)
Long-term debt issued	-	-	25,000
Long-term debt retired	(5,000)	(29,500)	(8,000)
Change in short-term debt - net	117,751	43,000	(26,600)
Cash dividend payments on common stock	(40,178)	(38,613)	(38,298)
Other	1,030	1,739	581
Cash provided by (used in) financing activities	75,913	(65,821)	(59,375)
Increase (decrease) in cash and cash equivalents	809	340	(1,376)
Cash and cash equivalents - beginning of period	6,107	5,767	7,143
Cash and cash equivalents - end of period	$ 6,916	$ 6,107	$ 5,767

Supplemental disclosure of cash flow information:			
Interest paid	$ 37,669	$ 38,508	$ 39,294
Income taxes paid	$ 12,300	$ 56,215	$ 31,270

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), which primarily consist of our regulated gas distribution business and our regulated gas storage business, which includes our wholly-owned subsidiary Gill Ranch Storage, LLC (Gill Ranch), and other investments and business activities, which primarily consist of our wholly-owned subsidiary NNG Financial Corporation (Financial Corporation) and an equity investment in a natural gas transmission pipeline (See Note 2).

In this report, the term utility is used to describe the gas distribution business and the term non-utility is used to describe the gas storage business and other non-utility investments and business activities (see Note 2). Intercompany accounts and transactions have been eliminated, except for transactions required by regulatory accounting under Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation, not to be 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.

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 businesses are the distribution of natural gas, which is regulated by the Oregon Public Utility Commission (OPUC), and Washington Utilities and Transportation Commission (WUTC), and gas storage services, which are regulated by the Federal Energy Regulatory Commission (FERC) and to a certain extent by the OPUC. Accounting records and practices of our regulated businesses conform to the requirements and uniform system of accounts prescribed by these regulatory authorities in accordance with SFAS No. 71. Our businesses are authorized by the OPUC, WUTC and the FERC 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 issued to provide for recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge.

Table of Contents

At December 31, 2008 and 2007, the amounts deferred as regulatory assets and liabilities were as follows:

	Current		Non-Current	
Thousands	2008	2007	2008	2007
Regulatory assets:				
Unrealized loss on non-trading derivatives[1]	$ 136,735	$ 14,788	$ 21,646	$ 3,758
Income tax asset	-	-	69,948	68,649
Pension and other postretirement benefit obligations[2]	8,074	1,912	113,869	27,152
Environmental costs - paid[3]	-	-	36,135	27,956
Environmental costs - accrued but not yet paid[3]	-	-	29,969	35,098
Other[4]	2,510	898	16,903	13,325
Total regulatory assets	$ 147,319	$ 17,598	$ 288,470	$ 175,938
Regulatory liabilities:				
Gas costs payable	$ 5,284	$ 46,153	$ 1,868	$ 6,290
Unrealized gain on non-trading derivatives[1]	4,592	2,903	146	324
Accrued asset removal costs	-	-	223,716	204,886
Other[4]	10,580	12,270	2,427	2,264
Total regulatory liabilities	$ 20,456	$ 61,326	$ 228,157	$ 213,764

(1) An unrealized gain or loss on non-trading derivatives does 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 purchased gas adjustment mechanism.

(2) Qualified pension plan and other postretirement benefit obligations 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).

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

(4) Other primarily consists of deferrals and amortizations under other approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

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, 2008 and 2007 will be recoverable or refundable through future utility rates. We annually review all regulatory assets for recoverability and more often if circumstances warrant. 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

Fair Value Measurements. In September 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 157, Fair Value Measurements, which is effective for fiscal years beginning after November 15, 2007. This statement defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. This statement indicates, among other things, that a fair value measurement assumes that a transaction to sell an asset or transfer a liability occurs in the principal market for the asset or liability or, in the absence of a principal market, the most advantageous market for the asset or liability. SFAS No. 157 defines fair value based upon an exit price model.

Relative to SFAS No. 157, the FASB issued FASB Staff Positions (FSP) 157-1, 157-2 and 157-3. FSP 157-1 amends SFAS No. 157 to exclude SFAS No. 13, Accounting for Leases, and its related interpretive accounting pronouncements that address leasing transactions. FSP 157-2 delays the effective date of the application of SFAS No. 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and liabilities except for those that are recognized or disclosed at fair value in the financial statements on a recurring basis. FSP 157-3, issued and effective on October 10, 2008, clarifies the application of SFAS No. 157 when relevant observable inputs in active markets are not available.

We adopted SFAS No. 157, FSP 157-1 and FSP 157-3 as of January 1, 2008, and adopted FSP 157-2 as of January 1, 2009. The adoption of these new accounting standards did not have, and is not expected to have, a material effect on our financial condition, results of operations or cash flows.

Fair Value Option for Financial Assets and Liabilities. In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities, which permits, but does not require, entities to measure many financial instruments and certain other items at fair value. SFAS No. 159 became effective for fiscal years beginning after November 15, 2007. We elected not to implement SFAS No. 159 because the majority of our assets and liabilities are regulated by the OPUC and the WUTC, both of which generally allow us to earn a reasonable return on invested capital based on original cost rather than current market value.

Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. On January 1, 2008, we adopted Emerging Issues Task Force (EITF) 06-11, Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards, which provides the accounting requirements for recognizing income tax benefits received on dividends paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options, and how these benefits are charged to retained earnings under SFAS No. 123R, Share Based Payment. The adoption of EITF 06-11 did not have, and is not expected to have, a material effect on our financial condition, results of operations or cash flows.

Offsetting Amounts Related to Certain Contracts. On January 1, 2008, we adopted FSP FASB Interpretation No. FIN 39-1 (FSP FIN39-1), Offsetting of Amounts Related to Certain Contracts. FSP FIN 39-1 requires disclosure when a reporting entity offsets fair value amounts from derivative instruments executed with the same counterparty under master netting arrangements. Our disclosures on FSP FIN 39-1 are included in Note 11. The adoption and implementation of FSP FIN 39-1 did not have, and is not expected to have, a material effect on our financial statement disclosures.

Transfers of Financial Assets and Interests in Variable Interest Entities. In December 2008, the FASB issued SFAS No. 140-4 and FIN 46R-8, Disclosures by Public Entities about Transfers of Financial Assets and Interests in Variable Interest Entities, effective immediately for periods ending after December 15, 2008. SFAS No. 140-4 and FIN 46R-8 require additional disclosures related to the nature of, involvement in and judgments made when transferring assets or liabilities to variable interest entities. The adoption and implementation of SFAS No. 140-4 and FIN 46R-8 did not have, and is not expected to have, a material effect on our financial statement disclosures.

Recent Accounting Pronouncements

Business Combinations. In December 2007, the FASB issued SFAS No. 141R, Business Combinations. This statement amends the principles and requirements for how an acquiror accounts for and discloses its business combinations. SFAS No. 141R is effective for fiscal years and interim periods beginning after December 15, 2008. Based on our preliminary assessment, this statement is not expected to have a material effect on our financial condition, results of operations or cash flows.

Noncontrolling Interests in Consolidated Financial Statements. In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements. This statement amends the reporting requirements of Accounting Research Bulletin No. 51 for noncontrolling interests in subsidiaries to improve the relevance, comparability and transparency of the financial information disclosed. SFAS No. 160 is effective for fiscal years beginning after December 15, 2008. Based on the nature of this new statement and our current organizational structure, adoption of this statement is not expected to have a material effect on our financial condition, results of operations or cash flows.

Derivative Instruments and Hedging Activities. In March 2008, the FASB issued SFAS No. 161, Accounting for Derivative Instruments and Hedging Activities, which requires enhanced disclosures of derivative instruments and hedging activities. SFAS No. 161 is effective for reporting periods beginning after November 15, 2008.

SFAS No. 161 will expand current disclosures by adding qualitative disclosures about our hedging objectives and strategies, fair value gains and losses, and credit-risk-related contingent features in derivative agreements. The disclosures are intended to provide an enhanced understanding of:

- how and why we use derivative instruments;
- how derivative instruments and related hedge items are accounted for under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, and its related interpretations; and
- how derivative instruments and related hedged items affect our financial condition, results of operations and cash flows.

The adoption of SFAS No. 161 is not expected to have a material effect on our financial statement disclosures.

Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities. In June 2008, the FASB issued final FSP No. EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions are Participating Securities. This statement requires nonforfeitable rights to dividends or dividend equivalents on unvested share-based payment to be included in the computation of earnings per share under the two-class method. This statement will be effective for fiscal years beginning

Table of Contents

after December 15, 2008. Based on our preliminary assessment, the adoption of FSP No. EITF 03-6-1 is not expected to have a material effect on our financial condition, results of operations or cash flows.

Pensions. In December 2008, the FASB issued SFAS No. 132R-1, Employers Disclosures about Pensions and Other Postretirement Benefits, which requires enhanced disclosures of plan assets in an employer s defined benefit pension or other postretirement benefit plan. SFAS No. 132R-1 is effective for reporting periods ending after December 15, 2009. The disclosures are intended to provide an enhanced understanding of:

- how investment allocation decisions are made;
- the major categories of plan assets;
- the inputs and valuation techniques used to measure the fair value of plan assets;
- the effect of fair value measurements using significant unobservable inputs (Level 3 input from SFAS No. 157) on changes in plan assets for the period; and
- significant concentration or risk within plan assets.

The adoption of SFAS No. 132R-1 is not expected to have a material effect on our financial statement disclosures.

Plant and Property and Accrued Asset Removal Costs

Plant and property is stated at cost, including capitalized labor, materials and overhead (see Note 9). In accordance with SFAS No. 71, the cost of constructing utility plant and gas storage assets generally includes an allowance for funds used during construction (AFUDC). AFUDC represents the net financing cost during the period the funds are used for construction purposes (see Allowance for Funds Used During Construction, below). When gas storage assets under construction are expected to be subject to market based rates, then the cost of construction will include capitalized interest in accordance with GAAP, not regulatory AFUDC.

Our provision for depreciation of utility property is computed under the straight-line, age-life method in accordance with external engineering studies and as approved by regulatory authorities. The weighted average depreciation rate for plant in service was approximately 3.4 percent for the years ended December 31, 2008, 2007 and 2006, reflecting the approximate average 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 approved depreciation studies. 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 net rate base.

Allowance for Funds Used During Construction

Certain additions to utility plant include AFUDC, which represents the net cost of borrowed or other funds used during construction and is calculated using actual current interest rates and authorized rates for return on equity, if applicable. If borrowings are less than the total costs of

Table of Contents

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 AFUDC. While cash is not realized currently from AFUDC, it is realized in future years through increased revenues from rate recovery resulting from higher rate base and higher depreciation expense. Our composite AFUDC rates were 3.6 percent in 2008, 5.4 percent in 2007 and 4.7 percent in 2006.

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, 2008 and 2007, book overdrafts of $1.0 million and $4.9 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 by billing cycle and weather. Accrued unbilled revenues are reversed the following month when actual billings occur. Our accrued unbilled revenues at December 31, 2008 and 2007 were $102.7 million and $78.0 million, respectively.

Utility operating revenues also include the recognition of a regulatory adjustment for income taxes paid. This revenue adjustment reflects an OPUC rule whereby we are required to implement a rate refund or a rate surcharge to utility customers. This automatic refund or surcharge is accrued based on the estimated difference between income taxes paid and income taxes authorized to be collected in rates for each tax year.

Non-utility revenues, derived primarily from gas storage services, are recognized as services are provided by the independent energy marketing company in accordance with our contractual agreement. Our current asset optimization agreement includes guaranteed amounts which are recognized pro-rata on a monthly basis over the contact term. 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 utility customers, plus amounts due for gas storage services and other miscellaneous receivables. With respect to these trade receivables, including accrued unbilled revenues, we establish an allowance for uncollectible accounts (allowance) based on the aging of receivables, collection experience of current past due accounts including 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 they are 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 uncollectible accounts is adjusted, as 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 cost recovery in customer rates. All gas that is injected into storage is priced into inventory based on actual 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. Material and supplies inventories are stated at the lower of average cost or net realizable value.

Derivatives

In accordance with SFAS No. 133, 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 or refund 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 purchased gas adjustment (PGA) rate has been set are subject to the PGA incentive sharing mechanism. Under our PGA sharing mechanism in effect prior to November 1, 2008, 67 percent of the changes in fair value were deferred as regulatory assets or liabilities and the remaining 33 percent was recorded to the income statement for derivatives that do not qualify for hedge accounting, and to Other Comprehensive Income for hedges that do qualify for hedge accounting. A modified PGA sharing mechanism was approved in Oregon, effective on November 1, 2008, under which we are required to select, by August 1 of each year, either an 80 percent deferral or 90 percent deferral of higher or lower gas costs such that the impact on current earnings from the gas cost sharing is either 20 percent or 10 percent, respectively. For the PGA year in Oregon beginning November 1, 2008, we selected the 80 percent deferral of gas cost differences. See Note 11.

Our financial derivatives policies set 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.

Fair Value

In accordance with SFAS No. 157, we use fair value measurements to record adjustments to certain financial assets and liabilities and to determine fair value disclosures. When developing fair value measurements, it is our policy to use quoted market prices whenever available, or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Fair values are primarily developed using industry-standard models that consider various inputs including: (a) quoted future prices for commodities; (b) forward currency prices; (c) time value; (d) volatility factors; (e) current market and contractual prices for underlying instruments; (f) market interest rates and yield curves; and (g) credit spreads, as well as other relevant economic measures. See Note 10.

Revenue Taxes

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

Income Tax Expense

NW Natural and its wholly-owned subsidiaries 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 $69.9 million and $68.6 million at December 31, 2008 and 2007, 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.

Other Income and Expense Net

Other income and expense net consists of income from company-owned life insurance, interest on deferred regulatory account balances and short-term debt cash investments, income from equity investments, gain on sale of investments, non-operating expenses related to our proposed pipeline project and other miscellaneous income and expense from merchandise sales, rents, leases and other items.

Thousands	2008	2007	2006
Gains from company-owned life insurance	$ 2,190	$ 1,939	$ 2,609
Interest income	250	537	363
Income from equity investments	667	130	191
Net interest on deferred regulatory accounts	552	84	(177)
Gain on sale of investments	1,737	1,544	-
Other	(1,650)	(2,789)	(852)
Total other income and expense - net	$ 3,746	$ 1,445	$ 2,134

Earnings Per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding each year. Diluted earnings per share reflect the potential effects of the exercise of stock options and other stock-based compensation. Diluted earnings per share are calculated as follows:

Thousands, except per share amounts	2008	2007	2006
Net income	$ 69,525	$ 74,497	$ 63,415
Average common shares outstanding - basic	26,438	26,821	27,540
Effect on shares from stock based compensation	156	174	117
Average common shares outstanding - diluted	26,594	26,995	27,657
Earnings per share of common stock - basic	$ 2.63	$ 2.78	$ 2.30
Earnings per share of common stock - diluted	$ 2.61	$ 2.76	$ 2.29

For the years ended December 31, 2008, 2007 and 2006, 1,248 shares, 442 shares and 4,681 shares, respectively, represent the number of stock options which were excluded from the calculation of diluted earnings per share because the effect was antidilutive.

2. CONSOLIDATED SUBSIDIARY OPERATIONS AND SEGMENT INFORMATION:

We operate in two primary reportable business segments, local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments which we aggregate and report as Other. We also refer to our local gas distribution business as the utility, and our gas storage and other business segments as non-utility. Our gas storage segment includes Gill Ranch, LLC (Gill Ranch), and our other segment includes our equity investment in a natural gas transmission pipeline and our Financial Corporation subsidiary.

Local Gas Distribution

Our local gas distribution segment is a regulated utility principally engaged in the purchase, sale and delivery of natural gas, including related services, to customers in Oregon and southwest Washington. As a regulated utility, we are responsible for building and maintaining a safe and reliable pipeline distribution system, purchasing sufficient gas supplies from producers and marketers, contracting for firm and interruptible transportation of gas over interstate pipelines to bring gas from the supply basins into our service territory, and re-selling the gas to customers subject to rates, terms and conditions approved by the OPUC or by the WUTC. Gas distribution also includes taking customer-owned gas and transporting it from interstate pipeline connections, or city gates, to the customers end-use facilities for a fee, also approved by the OPUC or WUTC. Approximately 90 percent of our customers are located in Oregon and 10 percent are in Washington. On an annual basis, residential and commercial customers typically account for about 55 percent of our utility s total volumes delivered and about 85 percent of gross operating revenues, while industrial customers account for about 45 percent of volumes and about 13 percent of gross revenues. The remaining 2 percent of gross operating revenues is derived from miscellaneous services and other regulatory charges.

Industrial customers we serve 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 group accounts for a significant portion of our revenues or margins.

Gas Storage

Our gas storage business segment includes natural gas storage services provided to interstate and intrastate customers in the Pacific Northwest using underground gas storage and pipeline facilities we own and operate. We also use an independent energy marketing company to provide asset optimization services for the utility under a contractual arrangement, the results of which are included in this business segment. For each of the years ended December 31, 2008, 2007 and 2006, this business segment derived a majority of its revenues from a few large storage customers who provide energy related services, including natural gas distribution, electric generation and energy marketing companies. Five storage customers currently account for over 90 percent of our existing contract storage capacity, with the largest customer accounting for about half of that total capacity. These five customers have contracts that expire at various dates through March 2015, with the largest customer s contract expiring in March 2015.

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 our utility assets when not needed to serve core utility customers. In Oregon, we retain 80 percent of the pre-tax income from these services 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 utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for crediting back to core utility customers. We have a similar sharing mechanism in Washington for revenue derived from storage and third party optimization.

In September 2007, we announced a joint project with Pacific Gas & Electric Company (PG&E) to develop a new underground natural gas storage facility at Gill Ranch near Fresno, California. We formed a wholly-owned subsidiary of NW Natural to develop and operate the facility. Gill Ranch Storage, LLC, will initially own 75 percent of the project, and PG&E will own 25 percent. As of December 31, 2008 and 2007, our investment balance in Gill Ranch was $13.1 million and $0.3 million, respectively.

Other

We have non-utility investments and other business activities which are aggregated and reported as a business segment called other. Although in the aggregate these investments and activities are not material, we identify and report them as a stand-alone segment based on our current organizational structure and decision-making process because these business investments and activities are not specifically related to our utility or gas storage segments. This segment primarily consists of an equity method investment in a joint venture to build and operate an interstate gas transmission pipeline in Oregon (Palomar) and other pipeline assets in Financial Corporation. This segment also includes some operating and non-operating expenses of the parent company that cannot be charged to utility operations. As of December 31, 2008 and 2007, our investment balance in Palomar was $14.2 million and $6.0 million, respectively. The total cost estimate for the entire 217-mile pipeline, if constructed, is estimated to be between $700 million and $800 million, with our current 50 percent share estimated at between approximately $350 million and $400 million. Palomar has executed binding precedent agreements with shippers, including our own utility, for a majority of the current design capacity on the pipeline. These agreements also provide commitments of credit support to the project. Our maximum loss exposure related to Palomar at December 31, 2008 would be limited to our investment balance of $14.2 million less any commitments or credit support from third parties.

In April 2008, NW Natural sold its investment in a Boeing 737-300 aircraft for approximately $6.8 million total including accrued rents. We purchased the aircraft in 1987 and leased it to Continental Airlines for the entire time it was owned by NW Natural. As a result of the sale, we recognized an after-tax gain of $1.1 million in the second quarter of 2008. In 2007, we sold our limited partnership interest in two wind power electric generation projects in California for $2.1 million, which resulted in an after-tax net gain on sale of $0.9 million.

Financial Corporation holds certain non-utility financial investments, but its assets primarily consist of an active, wholly-owned subsidiary which owns a 10 percent interest in an 18-mile interstate natural gas pipeline. Financial Corporation s total assets were $1.3 million and $1.4 million at December 31, 2008 and 2007, respectively.

Table of Contents

Segment Information Summary

The following table presents summary financial information about the reportable segments for the years ended 2008, 2007 and 2006. Inter-segment transactions are insignificant.

Thousands	Utility	Gas Storage	Other	Total
2008				
Net operating revenues	$ 337,596	$ 18,459	$ 160	$ 356,215
Depreciation and amortization	70,690	1,469	-	72,159
Income from operations	128,957	14,943	136	144,036
Net income	58,739	8,363	2,423	69,525
Total assets at Dec. 31, 2008	2,289,601	72,073	16,478	2,378,152
2007				
Net operating revenues	$ 351,875	$ 16,999	$ 168	$ 369,042
Depreciation and amortization	67,410	933	-	68,343
Income from operations	140,434	14,481	8	154,923
Net income	64,938	8,454	1,105	74,497
Total assets at Dec. 31, 2007	1,940,722	62,651	10,688	2,014,061
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
Net income	56,653	5,982	780	63,415

3. CAPITAL STOCK:

Common Stock

At the annual meeting of shareholders, held on May 22, 2008, our shareholders approved an amendment to our Restated Articles of Incorporation increasing the total number of authorized shares of common stock from 60 million to 100 million. At December 31, 2007, we had 60 million common shares authorized.

As of December 31, 2008, we had reserved for issuances 203,533 shares of common stock under the Employee Stock Purchase Plan (ESPP), 577,713 shares under our Dividend Reinvestment and Direct Stock Purchase Plan and 1,318,810 shares under our Restated Stock Option Plan (Restated SOP).

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, 2008 and 2007, our common stock and premium on common stock account balances are reflected on the balance sheet as common stock.

Stock Repurchase Program

We have a share repurchase program for our common stock under which we purchase shares on the open market or through privately negotiated transactions. We have Board authorization through May 2009 to repurchase up to an aggregate of 2.8 million shares, or up to $100.0 million. No shares of common stock were repurchased pursuant to this program in 2008. Since inception in 2000, a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

Table of Contents

Summary of Changes in Common Stock

The following table shows the changes in the number of shares of our common stock issued and outstanding for the years 2008, 2007 and 2006:

	Shares	Premium on common stock (thousands)
Balance, Dec. 31, 2005	27,579,296	$ 296,471
Sales to employees	31,397	-
Exercise of stock options - net	68,548	285
Repurchase	(395,500)	(1,461)
Change to no-par common stock	-	(295,295)
Balance, Dec. 31, 2006	27,283,741	$ -
Sales to employees	21,373	n/a
Exercise of stock options - net	75,850	n/a
Repurchase	(973,616)	n/a
Balance, Dec. 31, 2007	26,407,348	$ -
Sales to employees	19,500	n/a
Exercise of stock options - net [1]	74,340	n/a
Repurchase	-	n/a
Balance, Dec. 31, 2008	26,501,188	$ -

[1] For further details, see Restated SOP in Note 4.

4. STOCK-BASED COMPENSATION:

We have the following stock-based compensation plans: the Long-Term Incentive Plan (LTIP); the 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 may be purchased on the open market.

At December 31, 2008, 247,898 shares of common stock were available for award under the LTIP, assuming that performance based grants currently outstanding are awarded at the target level. The LTIP stock awards are compensatory awards for which compensation expense is recognized based on the fair value of performance-based stock awards earned, or a pro rata amortization over the vesting period for the outstanding awards of restricted stock.

Performance-based Stock Awards. Since the LTIP s inception in 2001, performance-based stock awards have been granted annually based on three-year performance periods. At December 31, 2008, certain performance-based stock award measures had been achieved for

Table of Contents

the 2006-08 award period. Accordingly, participants are estimated to receive 61,654 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. At December 31, 2007 and 2006, we awarded 66,666 and 40,446 shares of common stock, respectively, for the 2005-07 and 2004-06 award periods, plus 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. During 2008, we accrued and expensed $0.5 million related to the 2006-08 performance-based stock award, and on a cumulative basis we accrued a total $2.0 million related to the 2006-08 performance period. In 2007 and 2006, we accrued and expensed $0.6 million and $0.9 million, respectively, related to the 2005-07 and 2004-06 performance-based stock award periods, and on a cumulative basis we accrued a total of $2.0 million and $1.7 million, respectively.

At December 31, 2008, the aggregate number of performance-based shares granted and outstanding at the threshold, target and maximum levels were as follows:

Year	Performance	Performance Share Awards Outstanding		
Awarded	Period	Threshold	Target	Maximum
2007	2007-09	7,980	42,000	84,000
2008	2008-10	9,215	48,500	97,000
	Total	17,195	90,500	181,000

The threshold level estimates future payout assuming the minimum award payable is reached for each component of the formula in the LTIP. 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 per share grant date fair value of unvested shares at December 31, 2008 and 2007 was $14.73 and $25.45, respectively. The weighted-average per share grant date fair value of shares vested during the year was $38.40 and granted during the year was $10.89. In 2008, under these LTIP grants we accrued $1.0 million and expensed $0.9 million, while in 2007, we accrued $2.7 million and expensed $2.3 million and in 2006 we accrued and expensed $1.0 million.

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 8,334 restricted stock award shares were vested at December 31, 2008. Compensation expense is recognized ratably over the vesting period.

Restated Stock Option Plan. A total of 2,400,000 shares of common stock were reserved for issuance under the Restated SOP. Options under the Restated SOP 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 on the date of grant and may be exercised for a period not exceeding 10 years and 7 days from the date of grant. Option holders

Table of Contents

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.

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 and outcomes:

	February 2008	September 2008	2007	2006
Risk-free interest rate	2.8%	3.0%	4.7%	4.5%
Expected life (in years)	4.7	4.7	6.2	6.2
Expected market price volatility factor	18.4%	18.4%	17.2%	22.8%
Expected dividend yield	3.5%	2.9%	3.2%	4.0%
Forfeiture rate	3.8%	3.9%	4.4%	3.3%
Weighted average grant date fair value	$5.34	$7.05	$7.66	$6.29
Present value of options granted	$37.95	$44.50	$33.38	$26.00

The expected life of the 2008 grants was calculated based on our actual experience with previously exercised option grants. The simplified formula for plain vanilla options was used in 2007 and 2006 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. 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 vesting provisions of our option agreements.

Table of Contents

Information regarding the Restated SOP activity for the three years ended December 31, 2008 is summarized as follows:

	Option Shares	Price per Share Range	Price per Share Weighted - Average Exercise Price	Intrinsic Value *(In millions)*
Balance outstanding, Dec. 31, 2005	308,500	$20.25 - 38.30	$ 29.26	n/a
Granted	97,800	34.29	34.29	n/a
Exercised	(69,300)	20.25 - 31.34	27.15	$ 0.8
Forfeited	(3,000)	31.34 - 34.29	32.52	n/a
Balance outstanding, Dec. 31, 2006	334,000	20.25 - 38.30	31.14	n/a
Granted	100,600	44.48	44.48	n/a
Exercised	(75,850)	20.25 - 34.95	28.73	1.4
Forfeited	(1,000)	44.48	44.48	n/a
Balance outstanding, Dec. 31, 2007	357,750	20.25 - 44.48	35.36	4.8
Granted	119,050	43.29 - 51.09	43.62	n/a
Exercised	(74,340)	20.25 - 44.48	30.70	1.3
Forfeited	(6,050)	26.30 - 44.48	41.56	n/a
Balance outstanding, Dec. 31, 2008	396,410	$20.25 - 51.09	$ 38.62	$ 2.3
Shares available for grant				
Dec. 31, 2006				1,135,000
Dec. 31, 2007				1,035,400
Dec. 31, 2008				922,400

In the year ended December 31, 2008, cash of $2.3 million was received for option shares exercised and a $0.3 million related tax benefit was realized. For the 12 months ended December 31, 2008, 2007 and 2006, the total fair value of options that vested was $0.3 million, $0.2 million and $0.4 million, respectively.

The following table summarizes additional information about stock options outstanding and exercisable at December 31, 2008:

	Outstanding		Exercisable			
Range of Exercise Prices	Stock Options	Weighted-Average Remaining Life in Years	Stock Options	*(In millions)* Aggregate Intrinsic Value	Weighted-Average Exercise Price	Weighted-Average Remaining Life in Years
$20.25 - 51.09	396,410	7.47	167,410	$ 1.8	$ 33.77	6.04

As of December 31, 2008, there was $0.7 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2011.

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 12-month period. We use original issue shares for shares purchased under the plan.

Table of Contents

In accordance with SFAS No. 123R, stock-based compensation expense is recognized as operations and maintenance expense or is capitalized as part of construction overhead. The following table summarizes the allocations of stock-based compensation grants under our LTIP, Restated SOP and ESPP:

Thousands	2008	2007	2006
Operations and maintenance expense, for stock-based compensation	$ 1,598	$ 2,986	$ 2,304
Income tax effect	(623)	(1,165)	(898)
Net stock-based compensation effect on net income	$ 975	$ 1,821	$ 1,406
Amounts capitalized	$ 282	$ 479	$ 407

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 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 September 2004 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 at the time of the award. At December 31, 2008, all shares were fully vested.

5. COST AND FAIR VALUE BASIS OF 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 eligible property, including 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.

Table of Contents

The maturities on the long-term debt outstanding for each of the 12-month periods through December 31, 2013 amount to: none in 2009; $35 million in 2010; $10 million in 2011; $40 million in 2012; and none in 2013. Holders of certain long-term debt have put options that, if exercised, would accelerate the maturities by $20 million in 2009.

Thousands (December 31)	2008	2007	2006
Medium-Term Notes			
First Mortgage Bonds:			
6.31 % Series B due 2007[1]	$ -	$ -	$ 20,000
6.80 % Series B due 2007[2]	-	-	9,500
6.50% Series B due 2008[3]	-	5,000	5,000
4.11% Series B due 2010	10,000	10,000	10,000
7.45% Series B due 2010	25,000	25,000	25,000
6.665% Series B due 2011	10,000	10,000	10,000
7.13% Series B due 2012	40,000	40,000	40,000
8.26% Series B due 2014	10,000	10,000	10,000
4.70% Series B due 2015	40,000	40,000	40,000
5.15% Series B due 2016	25,000	25,000	25,000
7.00% Series B due 2017	40,000	40,000	40,000
6.60% Series B due 2018	22,000	22,000	22,000
8.31% Series B due 2019	10,000	10,000	10,000
7.63% Series B due 2019	20,000	20,000	20,000
9.05% Series A due 2021	10,000	10,000	10,000
5.62% Series B due 2023	40,000	40,000	40,000
7.72% Series B due 2025	20,000	20,000	20,000
6.52% Series B due 2025	10,000	10,000	10,000
7.05% Series B due 2026	20,000	20,000	20,000
7.00% Series B due 2027	20,000	20,000	20,000
6.65% Series B due 2027	20,000	20,000	20,000
6.65% Series B due 2028	10,000	10,000	10,000
7.74% Series B due 2030	20,000	20,000	20,000
7.85% Series B due 2030	10,000	10,000	10,000
5.82% Series B due 2032	30,000	30,000	30,000
5.66% Series B due 2033	40,000	40,000	40,000
5.25% Series B due 2035	10,000	10,000	10,000
	512,000	517,000	546,500
Less long-term debt due within one year	-	5,000	29,500
Total long-term debt	$ 512,000	$ 512,000	$ 517,000

[1] Redeemed at maturity in March 2007.

[2] Redeemed at maturity in May 2007.

[3] Redeemed at maturity in July 2008.

No long-term debt was issued during 2008 and 2007. In 2006, we issued and sold $25 million of 5.15 percent Series B secured medium term notes due 2016. Proceeds from this sale were used, in part, to repay short-term debt and fund our ongoing utility construction program.

Because we elected not to implement SFAS No. 159, we do not adjust our long-term debt balance to fair value. The following table provides an estimate of the fair value of our long-term debt, using market prices in effect on the valuation date. Interest rates for debt with similar

Table of Contents

credit ratings, terms and remaining maturities were used to estimate fair value for long-term debt issues.

	Dec. 31, 2008		Dec. 31, 2007	
Thousands	Carrying Amount	Estimated Fair Value[1]	Carrying Amount	Estimated Fair Value[1]
Long-term debt including amounts due within one year	$ 512,000	$ 505,828	$ 517,000	$ 557,916

(1) This estimate is calculated net of commission fees.

6. NOTES PAYABLE AND CREDIT FACILITIES:

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 one or more committed credit facilities. At December 31, 2008 and 2007, the amounts and average interest rates of commercial paper debt outstanding were $248.0 million and 1.6 percent and $143.1 million and 4.4 percent, respectively.

We have a multi-year $250 million syndicated credit agreement, pursuant to which we may extend commitments for additional one-year periods subject to lender approval. We extended commitments with six of the seven lenders under this credit agreement, with commitments totaling $210 million, to May 31, 2013. The credit agreement also allows us to request increases in the total commitment amount from time to time, up to a maximum amount of $400 million, and to replace any lenders who decline to extend the terms of the credit agreement. The credit agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. Any principal and unpaid interest owed on borrowings under the credit agreement are due and payable on or before the expiration date, which is May 31, 2013 for all except one lender, which has a commitment amount totaling $40 million that is due and payable on or before May 31, 2012. Additionally, we entered into two committed bilateral bank lines of credit totaling $30 million in November 2008, of which $15 million expired December 31, 2008 and $15 million expired February 27, 2009. There were no outstanding balances under this credit agreement and no letters of credit issued or outstanding at December 31, 2008 and 2007.

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

The syndicated credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2008 and

Table of Contents

2007, with a consolidated indebtedness to total capitalization ratio of 54.7 percent, and 52.7 percent, respectively.

7. PENSION AND OTHER POSTRETIREMENT BENEFITS:

We maintain two qualified non-contributory defined benefit pension plans, several non-qualified supplemental pension plans for eligible executive officers and certain key employees, and other postretirement benefit plans for certain 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 qualified defined benefit plan and the postretirement welfare plans for non-bargaining unit employees were closed to new employees. Instead, non-bargaining unit employees hired or re-hired after December 31, 2006 are currently provided an enhanced Retirement K Savings Plan (RKSP) benefit. Benefits provided to bargaining unit employees under the Retirement Plan for 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, 2008, and a summary of the funded status and amounts recognized in the consolidated balance sheets using measurement dates of December 31, 2008, 2007 and 2006:

	Postretirement Benefits					
	Pension Benefits			Other Benefits		
Thousands	2008	2007	2006	2008	2007	2006
Reconciliation of change in benefit obligation:						
Obligation at January 1	$ 260,561	$ 269,410	$ 267,854	$ 22,186	$ 22,436	$ 20,398
Service cost	6,141	8,708	7,745	521	505	555
Interest cost	17,373	16,057	14,901	1,403	1,293	1,184
Benefits paid	(16,247)	(15,924)	(13,183)	(1,259)	(1,299)	(1,015)
Plan amendments	5	3,887	-	-	-	15
Change in assumptions	9,146	(23,916)	(9,208)	839	(645)	133
Net actuarial (gain) or loss	4,291	2,339	1,301	173	(104)	1,166
Liability transfer	(143)	-	-	-	-	-
Obligation at December 31	$ 281,127	$ 260,561	$ 269,410	$ 23,863	$ 22,186	$ 22,436
Reconciliation of change in plan assets:						
Fair value of plan assets at January 1	$ 241,417	$ 236,518	$ 218,555	$ -	$ -	$ -
Actual return on plan assets	(63,267)	19,658	30,088	-	-	-
Employer contributions	1,211	1,166	1,058	1,259	1,298	1,015
Benefits paid	(16,247)	(15,924)	(13,183)	(1,259)	(1,298)	(1,015)
Fair value of plan assets at December 31	$ 163,114	$ 241,418	$ 236,518	$ -	$ -	$ -
Funded status:						
Funded status at December 31	$ (118,013)	$ (19,143)	$ (32,892)	$ (23,863)	$ (22,186)	$ (22,436)
Unrecognized transition obligation	-	-	-	1,646	2,058	2,469
Unrecognized prior service cost	6,963	8,212	5,512	1,669	1,866	2,063
Unrecognized net actuarial loss	116,239	20,995	45,862	2,525	1,514	2,288
Net amount recognized	$ 5,189	$ 10,064	$ 18,482	$ (18,023)	$ (16,748)	$ (15,616)

We adopted SFAS No. 158 effective December 31, 2006. 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. 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 are recognized as regulatory assets. An estimated $8.1 million for the qualified plans, consisting of $6.2 million of actuarial losses, $1.5 million of prior service costs and transition obligations of $0.4 million, will be amortized from the regulatory asset account to net periodic benefit cost in 2009. 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 2008, an estimated $0.4 million consisting of actuarial losses of $0.4 million and negligible prior service costs for the non-qualified plans were amortized from AOCI to net periodic benefit cost.

Our qualified defined benefit pension plans had an aggregate projected benefit obligation of $261.5 million, $243.1 million and $255.5 million at December 31, 2008, 2007 and 2006, respectively, and the fair value of plan assets was $163.1 million, $241.4 million and $236.5 million, respectively. Changes in valuation assumptions impact our projected benefit obligations. Benefit obligations at December 31, 2008 increased $7.4 million due to a decrease in our discount rate assumptions and increased by $5.0 million due to updating our mortality tables. The projected benefit obligations at December 31, 2007 decreased $23.9 million due to an increase in the discount rate assumptions and increased by $3.4 million due to an increase in the benefit payments for certain retirees. The combination of investment returns and future cash contributions by the company is expected to provide sufficient funds to cover all future benefit obligations of the plans.

An assumed discount rate was determined independently for each pension plan and other postretirement benefit plan based on the Citigroup Above Median Curve (discount rate curve) using high quality bonds (i.e. rated AA- or higher by Standard & Poor s or Aa3 or higher by Moody s Investors Service). The discount rate curve was then applied to match the estimated cash flows to reflect the timing and amount of expected 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 strategy and policies for the qualified pension plan assets held in the Retirement Trust Fund were approved by our retirement committee, which is composed of senior management employees. The policies set 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,

Table of Contents

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 and active portfolio management by professional investment managers. The Retirement Trust Fund is not currently invested in any NW Natural securities.

Our pension plan asset allocation at December 31, 2008 and 2007, and the target allocation and expected long-term rate of return by asset category, are as follows:

Asset Category	Percentage of Plan Assets Dec. 31, 2008	2007	Target Allocation	Expected Long-term Rate of Return
US Large Cap Equity	14.3%	18.1%	20%	8.50%
US Small/Mid Cap Equity	9.6%	13.1%	15%	9.50%
Non-US Equity	17.9%	24.9%	20%	8.75%
Fixed Income	21.2%	13.3%	15%	5.50%
Real Estate	11.3%	8.9%	8%	7.75%
Absolute Return Strategy	18.9%	16.3%	15%	9.00%
Real Return Strategy	6.8%	5.4%	7%	7.75%
Weighted Average				8.25%

Our non-qualified supplemental defined benefit pension plans benefit obligations were $19.6 million, $17.5 million and $13.9 million at December 31, 2008, 2007 and 2006, 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 are 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 company- and 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 $23.9 million, $22.2 million and $22.4 million at December 31, 2008, 2007 and 2006, respectively.

Net periodic benefit cost consists 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.

Table of Contents

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, 2008, 2007 and 2006 and the assumptions used in measuring these costs and benefit obligations:

	Pension Benefits			Other Postretirement Benefits		
Thousands	2008	2007	2006	2008	2007	2006
Service cost	$ 6,141	$ 8,708	$ 7,745	$ 521	$ 505	$ 556
Interest cost	17,373	16,057	14,901	1,403	1,293	1,184
Expected return on plan assets	(19,087)	(18,490)	(17,611)	-	-	-
Amortization of transition obligations	19	-	-	411	411	411
Amortization of prior service costs	1,253	1,188	979	197	197	195
Amortization of net loss	385	2,123	3,520	-	25	1
Net periodic benefit cost	$ 6,084	$ 9,586	$ 9,534	$ 2,532	$ 2,431	$ 2,347
<u>Assumptions for net periodic benefit cost:</u>						
Discount rate	6.76%-6.87%	6.0%-6.05%	5.75%	6.56%	5.91%	5.75%
Rate of increase in compensation	3.5%-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
<u>Assumptions for funded status:</u>						
Discount rate	6.44%-6.72%	6.76%-6.87%	6.0%-6.05%	7.12%	6.56%	5.91%
Rate of increase in compensation	3.5%-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 other postretirement benefits as of December 31, 2008 were 9.5 percent for medical and 11.5 percent for prescription drugs. Medical costs were assumed to decrease gradually each year to a rate of 5.0 percent by 2017, while prescription drug costs were assumed to decrease gradually each year to a rate of 5.0 percent by 2022.

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	$ 51	$ (45)
Effect on health care cost component of the accumulated postretirement benefit obligation	$ 732	$ (646)

Table of Contents

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, 2008 and 2007, and estimated future payments:

Thousands				
Employer Contributions by Plan Year		Pension Benefits		Other Benefits
2007	$	1,606	$	1,298
2008		1,645		1,259
2009 (estimated)		10,391		2,063
Benefit Payments				
2006	$	13,183	$	1,015
2007		15,924		1,298
2008		16,247		1,259
Estimated Future Payments				
2009	$	16,476	$	2,063
2010		17,030		2,096
2011		17,385		2,171
2012		18,293		2,101
2013		18,761		2,810
2014-2018		106,004		10,384

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. The Pension Protection Act of 2006 (the Act) established new funding requirements for defined benefit plans. The Act establishes a 100 percent funding target for plan years beginning after December 31, 2008. However, a delayed effective date of 2011 may apply if the pension plan meets the funding targets of 92 percent in 2008, 94 percent in 2009 and 96 percent in 2010. Our qualified defined benefit pension plans are currently underfunded by $98 million at December 31, 2008, and we expect to make at least the minimum contribution required pursuant to the Act, which is currently estimated at $8 million. We plan to make an additional contribution during 2009, which could bring the total contribution in 2009 up to $40 million. We would need to make a total contribution in 2009 of at least $17 million to avoid any restrictions on benefit payments.

Our 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 $2.1 million in 2008, $1.9 million in 2007, and $1.8 million in 2006. The RKSP includes an Employee Stock Ownership Plan. In addition, we make contributions on behalf of each union employee to the Western States Office and Professional Employees Pension Fund, a multi-employer plan. Our contributions totaled $0.4 million in 2008 and 2007 and $0.5 million in 2006.

Table of Contents

8. INCOME TAXES:

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

Thousands, except percentages	2008	2007	2006
Income taxes at federal statutory rate	$ 38,571	$ 41,495	$ 34,877
Increase (decrease):			
Current state income tax, net of federal tax benefit	4,100	4,566	3,655
Amortization of investment and energy tax credits	(646)	(881)	(994)
Differences required to be flowed-through by regulatory commissions	(704)	(704)	(704)
Gains on company and trust-owned life insurance	(767)	(679)	(913)
Other - net	124	263	313
Total provision for income taxes	$ 40,678	$ 44,060	$ 36,234
Federal statutory tax rate	35.0%	35.0%	35.0%
Increase (decrease):			
Current state income tax, net of federal tax benefit	3.7%	3.9%	3.7%
Amortization of investment and energy tax credits	-0.6%	-0.7%	-1.0%
Differences required to be flowed-through by regulatory commissions	-0.6%	-0.6%	-0.7%
Gains on company and trust-owned life insurance	-0.7%	-0.6%	-0.9%
Other - net	0.1%	0.2%	0.3%
Effective tax rate	36.9%	37.2%	36.4%

The provision for income taxes consists of the following:

Thousands	2008	2007	2006
Current			
Federal	$ (7,970)	$ 41,086	$ 44,785
State	(437)	7,764	7,836
	(8,407)	48,850	52,621
Deferred			
Federal	42,862	(4,107)	(14,180)
State	6,223	(683)	(2,207)
	49,085	(4,790)	(16,387)
Total provision for income taxes	$ 40,678	$ 44,060	$ 36,234
Total income taxes paid	$ 12,300	$ 56,215	$ 31,270

Table of Contents

The following table summarizes the total provision (benefit) for income taxes for the regulated utility and other non-utility business segments for the three years ended December 31, 2007:

Thousands	2008	2007	2006
Regulated utility:			
Current	$ (13,034)	$ 43,587	$ 48,469
Deferred	48,790	(3,856)	(14,810)
Deferred investment and energy tax credits	(646)	(713)	(756)
	35,110	39,018	32,903
Non-utility business segments:			
Current	4,627	5,263	4,152
Deferred	941	(53)	(583)
Deferred investment and energy tax credits	0	(168)	(238)
	5,568	5,042	3,331
Total provision for income taxes	$ 40,678	$ 44,060	$ 36,234

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

Thousands	2008	2007
Deferred tax liabilities:		
Plant and property	$ 183,462	$ 159,506
Regulatory adjustment for income taxes paid	2,374	2,356
Regulatory income tax assets	69,948	68,649
Regulatory liabilities	8,145	478
Non-regulated deferred tax liabilities	426	249
Total	264,355	231,238
Deferred tax assets:		
Regulatory assets	(4,335)	(25,973)
Unfunded pension and postretirement obligations	(2,709)	(2,118)
Non-regulated deferred tax assets	(471)	-
Loss and credit carryforwards	(1,557)	-
Total	(9,072)	(28,091)
Deferred income tax liabilities - net	255,283	203,147
Deferred investment tax credits	2,548	3,193
Deferred income taxes and investment tax credits	$ 257,831	$ 206,340

We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2008.

102

Table of Contents

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

Thousands	2008
Deferred tax expense, above	$ 49,731
Increase in differences required to be flowed-through	1,299
Decrease in minimum pension liability included in AOCI	(591)
Decrease in deferred taxes associated with asset held for sale	1,698
Decrease in deferred investment tax credits	(646)
Change in deferred income tax accounts	$ 51,491

We calculate our deferred tax assets and liabilities under SFAS No. 109, whereby deferred income taxes are generally determined based on the difference between the financial statement and tax basis of assets and liabilities using enacted tax rates in effect in the years in which the differences are expected to reverse. 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 utility ratemaking process.

On February 13, 2008, the Economic Stimulus Act (ESA) was enacted providing an additional first-year tax deduction for depreciation equal to 50 percent of the adjusted basis of qualified property. The extra 50 percent depreciation deduction in the first year is an acceleration of depreciation deductions that otherwise would have been taken in the later years of an asset s recovery period. The accelerated depreciation provisions provided by the ESA is expected to expire at December 31, 2008. During 2008, we reduced income taxes currently payable by an estimated $13.6 million.

For the year ended December 31, 2008, we had an estimated net operating loss (NOL) for federal and Oregon income tax purposes of $19.2 million and $23.8 million, respectively, primarily due to the effects of accelerated tax depreciation provided by the ESA. The federal NOL will be carried back to 2006 for a refund of taxes paid in prior years and the Oregon NOL will be carried forward to reduce future taxable income. We anticipate that we will be able to use all loss carryforwards in future years. The 2008 Oregon NOL will expire in 2023.

In July 2006, FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109 (FIN 48), which clarifies the accounting for uncertainty in income taxes recognized in the financial statements in accordance with SFAS No. 109. FIN 48 requires the use of a two-step approach for recognizing and measuring tax positions taken or expected to be taken in a tax return. First, a tax position should only be recognized when it is more likely than not, based on technical merits, that the position will be sustained upon examination by the taxing authority. Second, a tax position that meets the recognition threshold should be measured at the largest amount that has a greater than 50 percent likelihood of being sustained. We adopted FIN 48 as of January 1, 2007, and had no material unrecognized tax benefits upon adoption or for the years ended December 31, 2008 and 2007. As a result, no interest or penalties were accrued for unrecognized tax benefits during the year. The IRS has completed and closed its examination of the Company s 2002, 2003 and 2004 tax years. The years after 2004 remain open to further examination by the IRS.

Table of Contents

9. PROPERTY AND INVESTMENTS:

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

	2008		2007	
Thousands, except percentages	Amount	Weighted Average Depreciation Rate	Amount	Weighted Average Depreciation Rate
Transmission and distribution	$ 1,810,747	3.3%	$ 1,735,934	3.3%
Utility storage	116,035	2.5%	112,984	2.6%
General	100,838	3.2%	96,612	3.0%
Intangible and other	77,650	9.0%	71,044	8.8%
Gas stored long-term	14,133	0.0%	14,232	0.0%
Utility plant in service	2,119,403	3.4%	2,030,806	3.4%
Construction work in progress	23,585		21,355	
Total utility plant	2,142,988		2,052,161	
Less accumulated depreciation	(659,123)		(615,533)	
Utility plant-net	$ 1,483,865		$ 1,436,628	

Accumulated depreciation does not include the accumulated provision for asset removal costs of $223.7 million and $204.9 million at December 31, 2008 and 2007, respectively. These accrued asset removal costs are 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:

	2008		2007	
Thousands, except percentages	Amount	Weighted Average Depreciation Rate	Amount	Weighted Average Depreciation Rate
Non-utility storage	$ 60,515		$ 54,083	
Other	4,886		4,881	
Non-utility plant in service	65,401	2.5%	58,964	2.1%
Construction work in progress	9,105		8,185	
Total non-utility plant	74,506		67,149	
Less accumulated depreciation	(9,314)		(7,904)	
Non-utility plant - net	$ 65,192		$ 59,245	

Table of Contents

The following table summarizes other long-term investments, including financial investments in life insurance policies accounted for at fair value and equity investments in certain partnerships and joint ventures accounted for under the equity or cost methods, at December 31:

Thousands	2008	2007
Life insurance investments	$ 35,427	$ 46,294
Note receivable	518	518
Investment in gas pipeline joint venture	15,214	7,258
Other	2,973	-
Total other investments	$ 54,132	$ 54,070

Life Insurance Investment. We have invested in key person life insurance contracts to provide an indirect funding vehicle for certain long-term employee benefit plan liabilities. The amount in the above table is reported as cash surrender value, net of policy loans.

Investment in Gas Pipeline Joint Venture. A wholly-owned subsidiary of Financial Corporation, KB Pipeline Company, owns a 10 percent interest in an 18-mile interstate natural gas pipeline. Also, in 2007, we entered into an agreement with TransCanada s Gas Transmission Northwest (GTN) for the purpose of designing, permitting, constructing and owning a pipeline that would connect GTN s interstate transmission pipeline to our local gas distribution system to serve markets in Oregon and the western United States. As of December 31, 2008, our investment balance in Palomar was $14.2 million, primarily related to planning and permitting.

Variable Interest Entities. FASB Interpretation No. 46(R), Consolidation of Variable Interest Entities, provides guidance for determining whether consolidation is required for entities known as variable interest entities over which control is achieved through means other than voting rights or entities that do not have sufficient equity investment at risk to permit financing its activities without additional financial support. We currently have a variable interest in Palomar, which is accounted for as an equity investment and not consolidated as we are not the primary beneficiary. See Note 2.

10. FAIR VALUE OF FINANCIAL INSTRUMENTS:

We use fair value measurements to record fair value adjustments to certain financial instruments and to determine fair value disclosures. As of December 31, 2008, we recorded our derivatives at fair value according to SFAS No. 157. As we elected not to implement SFAS No. 159, we did not measure our long-term debt at fair value (see Note 1).

In accordance with SFAS No. 157, we use the following fair value hierarchy for determining our derivative fair value measurements:

Level 1: Valuation is based upon quoted prices for identical instruments traded in active markets;
Level 2: Valuation is based upon quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-based valuation techniques for which all significant assumptions are observable in the market; and

Level 3: Valuation is generated from model-based techniques that use significant assumptions not observable in the market. These unobservable assumptions reflect our own estimates of assumptions that market participants would use in valuing the asset or liability.

When developing fair value measurements, it is our policy to use quoted market prices whenever available, or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Derivative contracts outstanding at December 31, 2008 were measured at fair value using models or other market-accepted valuation methodologies derived from observable market data. These quoted prices are primarily industry-standard models that consider various inputs including: (a) quoted future prices for commodities; (b) forward currency prices; (c) time value; (d) volatility factors; (e) current market and contractual prices for underlying instruments; (f) market interest rates and yield curves; and (g) credit spreads, as well as other relevant economic measures.

In accordance with SFAS No. 157, we include nonperformance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. Our assessment of nonperformance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at December 31, 2008.

The following table provides the fair value hierarchy of our derivative assets and liabilities as of December 31, 2008:

Thousands	Fair Value Measurements	
Hierarchy	Description of Derivative Inputs	Fair Value, net
Level 1	Quoted prices in active markets	$ -
Level 2	Significant other observable inputs	(153,643)
Level 3	Significant unobservable inputs	-
		$(153,643)

11. USE OF FINANCIAL DERIVATIVES:

We have entered into swaps, options and combinations of options for the purchase of natural gas and for the forecasted issuance of fixed-rate debt that qualify as derivative instruments under SFAS No. 133. We primarily use derivative financial instruments to manage commodity prices related to our natural gas requirements and to manage interest rate risk exposure related to our long-term debt issuances.

In the normal course of business, we enter into indexed-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 our annual 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 80 percent of the changes in fair value are deferred as regulatory assets or liabilities and the remaining 20 percent is recorded to

Table of Contents

the income statement for contracts not qualifying for hedge accounting and to Other Comprehensive Income for contracts qualifying for hedge accounting.

Certain natural gas purchases from Canadian suppliers are payable in Canadian dollars, including both commodity and demand charges, which expose 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 regulatory 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, 2008 was an unrealized loss of $0.4 million. This unrealized loss is subject to regulatory deferral and, as such, was recorded as a derivative liability, which is offset by recording a corresponding amount to a regulatory asset account.

In 2007, we entered into a 10-year, $50 million fixed-price forward starting interest rate swap contract to hedge the interest rate exposure related to the forecasted issuance of long-term debt. This interest rate swap is an effective cash flow hedge under SFAS No. 133.

The unrealized mark-to-market value at December 31, 2008 for all derivative contracts outstanding was a total loss of $153.6 million consisting of the following: a $141.3 million unrealized loss on natural gas commodity hedge and derivative contracts, a $11.9 million unrealized loss on the interest rate swap contract and a $0.4 million unrealized loss on the foreign exchange forward contracts.

Derivative hedge contracts are subject to a hedge effectiveness test to determine the financial statement treatment of each specific derivative. As of December 31, 2008, all of our derivatives were effective economic hedges and either qualified or were expected to qualify for regulatory deferral, or hedge accounting treatment. We use the hypothetical derivative method under SFAS No. 133 to determine the hedge effectiveness of our interest rate swap which qualifies as a cash flow hedge. We extended the effective date of our interest rate swap from December 1, 2008 to April 1, 2009 which resulted in an ineffectiveness of $1.5 million. In accordance with SFAS No. 71, we have reclassified this amount from AOCI to regulatory assets. The ineffectiveness for all other derivative contracts is determined using the dollar offset method under SFAS No. 133. The effectiveness test applied to financial derivatives is dependent on the type of derivative and its use.

Table of Contents

At December 31, 2008 and 2007, the unrealized gains or losses from mark-to-market valuations of our derivative instruments were primarily recorded as regulatory liabilities or regulatory assets because the realized gains or losses at settlement are either included, or are expected to be included, in utility rates 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 a Black-Scholes model for options, were as follows:

	Fair Value Gains (Losses)			
Thousands	Dec. 31, 2008		Dec. 31, 2007	
	Current	Non-Current	Current	Non-Current
Natural gas commodity-based derivative instruments:				
Natural gas commodity hedge contracts	$ (131,698)	$ (9,588)	$ (12,099)	$ (2,104)
Interest rate hedge contract	-	(11,912)	-	(1,330)
Foreign currency forward purchase contracts	(445)	-	173	-
Total	$ (132,143)	$ (21,500)	$ (11,926)	$ (3,434)

In 2008 and 2007, we realized net gains of $35.1 million and net losses of $42.0 million, respectively, from the settlement of fixed-price natural gas financial swap contracts which were recorded as decreases and increases to the cost of gas, respectively. Realized losses in 2007 were offset by lower gas purchase costs from the underlying hedged item, which were 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. There were no realized gains or losses on the interest rate swap during 2008.

As of December 31, 2008, all of our natural gas financial hedge contracts mature on or before October 2010. The maturity date on our interest rate swap contract is in April 2019.

12. COMMITMENTS AND CONTINGENCIES:

Lease Commitments

We lease land, buildings and equipment under agreements that expire in various years through 2095. Rental expense under operating leases was $4.7 million, $4.6 million and $4.4 million for the years ended December 31, 2008, 2007 and 2006, respectively. The table below reflects the future minimum lease payments due under non-cancelable leases at December 31, 2008. Such payments total $47.3 million for operating leases. The net present value of payments on capital leases less imputed interest was $1.2 million. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities, vehicles and computer equipment.

Thousands	2009	2010	2011	2012	2013	Later years
Operating leases	$ 4,129	$ 4,127	$ 4,080	$ 4,230	$ 4,268	$ 26,501
Capital leases	599	461	163	21	-	-
Minimum lease payments	$ 4,728	$ 4,588	$ 4,243	$ 4,251	$ 4,268	$ 26,501

Table of Contents

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 short-term and long-term gas purchase agreements. The aggregate amounts of these agreements were as follows at December 31, 2008:

Thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2009	$ 229,804	$ 84,798	$ 4,128
2010	89,079	64,554	3,440
2011	34,835	64,175	-
2012	21,277	49,067	-
2013	21,277	41,602	-
2014 through 2028	17,731	87,826	-
Total	414,003	392,022	7,568
Less: Amount representing interest	7,698	27,861	56
Total at present value	$ 406,305	$ 364,161	$ 7,512

Our total payments of fixed charges under capacity purchase agreements in 2008, 2007 and 2006 were $85.7 million, $90.1 million and $69.2 million, respectively. Included in the amounts were reductions for capacity release sales of $5.0 million for 2008, $5.3 million for 2007 and $3.7 million for 2006. 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 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 us, 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. In addition, disputes may arise between potentially responsible parties and regulators as to the severity of particular environmental matters and what remediation efforts are appropriate. These disputes could lead to adversarial administrative proceedings or litigation, with uncertain outcomes.

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 May 2007, we completed a revised Upland Remediation Investigation Report and submitted it to the ODEQ for review. In November 2007 we submitted a Focused Feasiblity Study to DEQ for groundwater source control. We have a net liability accrued of $20.1 million at December 31, 2008 for the Gasco site, which is estimated at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Siltronic site. We previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (the Siltronic site). We are currently implementing an investigation of manufactured gas plant wastes on the uplands at this site for the DEQ. The net liability accrued at December 31, 2008 for the Siltronic site is $1.0 million, which is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

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 and Siltronic sites. 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. We then joined with other potentially responsible parties, referred to as the Lower Willamette Group, to fund environmental studies in the Portland Harbor. 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), completion of which is currently expected in 2010. The EPA and the Lower Willamette Group are conducting focused studies on approximately nine miles of the lower Willamette River, including the 5.5-mile segment previously studied by the EPA. In 2008, we received a revised estimate and updated our estimate for additional expenditures related to RI/FS development and environmental remediation. In August 2008, we signed a cooperative agreement to participate in a phased natural resource damage assessment, with the intent to identify what, if any, additional information is necessary to estimate further liabilities sufficient to support an early restoration-based settlement of natural resource damage claims. As of December 31, 2008, we have a net liability accrued of $13.2 million for this site, which is at the low end of the range of the potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

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 total cost of removal, including technical work, oversight, consultant fees, legal fees and ongoing monitoring, was about $10.8 million. To date, we have paid $10.1 million on work related to the removal of the tar deposit. As of December 31, 2008, we have a net liability accrued of $0.7 million for our estimate of ongoing costs related to the tar deposit removal.

Central Service Center site. In 2006, we received notice from the ODEQ that our Central Service Center in southeast Portland (the Central Service Center site) was 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 as a result of 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. In early 2007, we received notice that this site was added to the ODEQ s list of sites where releases of hazardous substances have been confirmed and its list where additional investigation or cleanup is necessary. We are currently performing an environmental investigation of the property with the ODEQ s Independent Cleanup Pathway. As of December 31, 2008, we have recorded an estimated liability of $0.5 million for investigation at this site. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated. Although it is outside the geographic scope of the current Portland Harbor site sediment studies, the EPA directed the Lower Willamette Group to collect a series of surface and subsurface sediment samples off the river bank adjacent to where that facility was located. Based on the results of that sampling, the EPA notified the Lower Willamette Group that additional sampling would be required. As the Front Street site is upstream from the Portland Harbor site, the EPA agreed that it could be managed separately from the Portland Harbor site under ODEQ authority. As of December 31, 2008, we accrued an estimated liability of $0.3 million for the study of the site, which will include investigation of sediments and provide a report of historical upland activities. The estimate is at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot reasonably be estimated.

Table of Contents

Oregon Steel Mills site. See Legal Proceedings, below.

Accrued Liabilities Relating to Environmental Sites. The following table summarizes the accrued liabilities relating to environmental sites at December 31, 2008 and 2007:

	Current Liabilities		Non-Current Liabilities	
Thousands	2008	2007	2008	2007
Gasco	$ 6,012	$ 6,901	$ 14,071	$ 14,342
Siltronic	682	-	332	1,540
Portland Harbor	277	-	13,642	14,821
Central Service Center	-	-	526	529
Front Street	-	-	294	2
Other	-	-	80	165
Total	$ 6,971	$ 6,901	$ 28,945	$ 31,399

Regulatory and Insurance Recovery for Environmental Costs. In May 2003, the OPUC approved our request to defer unreimbursed environmental costs associated with certain named sites, including those described above. Beginning in 2006, the OPUC authorized us to accrue interest on deferred environmental cost balances, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, this authorization has been extended through January 25, 2009. We have requested another extension through January 2010, and that request is currently pending.

On a cumulative basis, we have recognized a total of $70.9 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $35.0 million has been spent to date and $35.9 million is recorded as an outstanding liability. At December 31, 2008, we had a regulatory asset of $66.1 million, which includes $30.1 million of total paid expenditures to date, $30.0 million for additional environmental costs expected to be paid in the future and accrued interest of $6.0 million. We believe the recovery of these deferred charges is probable through the regulatory process. We intend to pursue recovery of an insurance receivable and environmental regulatory deferrals from insurance carriers under 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 most 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 law that allows an insured party to seek recovery of all sums from one insurance company. We have initiated settlement discussions with a majority of our insurers but continue to anticipate that our overall insurance recovery effort will extend over several years.

Table of Contents

As such we have classified our regulatory assets for environmental cost deferrals as non-current. The following table summarizes the non-current regulatory assets relating to environmental sites at December 31, 2008 and 2007:

	Non-Current Regulatory Assets	
Thousands	2008	2007
Gasco	$ 30,707	$ 29,042
Siltronic	2,327	2,227
Portland Harbor	31,791	30,869
Central Service Center	545	545
Front Street	338	1
Other	396	370
Total	$ 66,104	$ 63,054

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 matter described below, cannot be predicted with certainty, we do not expect that the ultimate disposition of any of these matters will have a material adverse effect on our financial condition, results of operations or cash flows.

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 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. 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.

Table of Contents

NORTHWEST NATURAL GAS COMPANY

QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Quarter ended				
Thousands, except per share amounts	March 31	June 30	Sept. 30	Dec. 31	Total
2008					
Operating revenues	$ 387,694	$ 191,254	$ 109,702	$ 349,205	$ 1,037,855
Net operating revenues	132,423	62,572	43,549	117,671	356,215
Net income (loss)	43,168	3,297	(10,120)	33,180	69,525
Basic earnings (loss) per share	1.63	0.12	(0.38)	1.25	2.63(1)
Diluted earnings (loss) per share	1.63	0.12	(0.38)	1.25	2.61(1)
2007					
Operating revenues	$ 394,091	$ 183,249	$ 124,245	$ 331,608	$ 1,033,193
Net operating revenues	139,008	64,118	49,663	116,253	369,042
Net income (loss)	48,075	2,617	(5,908)	29,713	74,497
Basic earnings (loss) per share	1.77	0.10	(0.22)	1.12	2.78(1)
Diluted earnings (loss) per share	1.76	0.10	(0.22)	1.11	2.76(1)

(1) 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.

Table of Contents

NORTHWEST NATURAL GAS COMPANY

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C Additions		COLUMN D Deductions	COLUMN E Balance
	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Net Write-offs	at end of period
Thousands (year ended Dec. 31)					
2008					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 2,890	$ 3,145	$ -	$ 3,108	$ 2,927
2007					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 3,033	$ 2,978	$ -	$ 3,121	$ 2,890
2006					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 3,067	$ 3,036	$ -	$ 3,070	$ 3,033

115

Table of Contents

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

Our management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has completed an evaluation of 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 (the Exchange Act)). Based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of December 31, 2008, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us and included in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer as appropriate to allow timely decisions 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 the quarter ended December 31, 2008 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.

Table of Contents

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS 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 28, 2009 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 28, 2009 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2008	Positions held during last five years
Mark S. Dodson	63	Chief Executive Officer (2007-2008); President and Chief Executive Officer (2003-2007).
Gregg S. Kantor	51	President and Chief Executive Officer (2009-); President and Chief Operating Officer (2007 - 2008); Executive Vice President (2006-2007); Senior Vice President, Public and Regulatory Affairs (2003-2006).
David H. Anderson	47	Senior Vice President and Chief Financial Officer (2004-); Senior Vice President and Chief Financial Officer, TXU Gas Company (2004); Senior Vice President, Principal Accounting Officer and Controller TXU Corp. (2003-2004).
Margaret D. Kirkpatrick	54	Vice President and General Counsel (2005-); Partner, Stoel Rives LLP (1991-2005).
Lea Anne Doolittle	53	Senior Vice President (2008-); Vice President, Human Resources (2000-2007).
J. Keith White	55	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).
David R. Williams	55	Vice President, Utility Services (2007-); Director, Acquire Customers (2006); Director, Gas Operations (2005-2006); General Manager, Utility Operations (1999-2004).
Grant M. Yoshihara	53	Vice President, Utility Operations (2007-); Managing Director, Utility Services (2005-2006); General Manager, Consumer Services (2003-2004).
C. Alex Miller	51	Vice President, Finance and Regulation (2009-); General Manager of Rates and Regulatory Affairs (2002-2009).
Stephen P. Feltz	53	Treasurer and Controller (1999-).
MardiLyn Saathoff	52	Chief Governance Officer and Corporate Secretary (2008-); Chief Compliance Officer and Assistant General Counsel, Tektronix, Inc. (2005-2008); General Counsel to Oregon Governor Kulongoski and Business and Economic Development Advisor (2003-2005).

Each executive officer serves successive annual terms; present terms end on May 28, 2009. There are no family relationships among our executive officers, directors or any person chosen to become one of our officers or directors.

Table of Contents

NW Natural has adopted a Code of Ethics applicable to 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. We intend to disclose on our website at *www.nwnatural.com* any amendments to or waivers of our Code of Ethics for executive officers.

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 28, 2009 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2008 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, 2008 (see Note 4 to the Consolidated Financial Statements):

Plan Category	**(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]	75,000	n/a	247,898
Restated Stock Option Plan	396,410	$ 38.62	922,400
Employee Stock Purchase Plan	15,119	$ 43.25	188,414
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)[2]	6,300	n/a	n/a
Directors Deferred Compensation Plan (DDCP)[2]	72,767	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)[3]	47,617	n/a	n/a
Non-Employee Directors Stock Compensation Plan[4]	n/a	n/a	n/a
Total	613,213		1,358,712

The information captioned Beneficial Ownership of Common Stock by Directors and Executive Officers contained in our definitive Proxy Statement for the May 28, 2009 Annual Meeting of Shareholders is incorporated herein by reference.

Table of Contents

[1] Shares issued pursuant to the LTIP do not include an exercise price, but are payable when the award criteria are satisfied. If the maximum awards were paid pursuant to the performance-based awards outstanding at December 31, 2008, the number of shares shown in column (a) would increase by 71,834 shares and the number of shares shown in column (c) would decrease by 71,834 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. Cash accounts are credited quarterly with interest at a rate equal to Moody s Average Corporate Bond Yield plus two percentage points, subject to a six percent minimum rate. 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. 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 10 years as elected by the participant in accordance with the terms of the DCP. We have contributed common stock to the trustee of the Supplemental Trust such that this trust holds approximately the number of common shares equal to the number of shares credited to all participates stock accounts. 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 28, 2009 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned 2008 and 2007 Audit Firm Fees in the Company s definitive Proxy Statement for the May 28, 2009 Annual Meeting of Shareholders is hereby incorporated by reference.

Table of Contents

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 123.

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 27, 2009

By: /s/ Gregg S. Kantor
Gregg S. Kantor,

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/ Gregg S. Kantor Gregg S. Kantor President and Chief Executive Officer	Principal Executive Officer and Director		February 27, 2009
/s/ David H. Anderson David H. Anderson Senior Vice President and Chief Financial Officer	Principal Financial Officer		February 27, 2009
/s/ Stephen P. Feltz Stephen P. Feltz Treasurer and Controller	Principal Accounting Officer		February 27, 2009
/s/ Timothy P. Boyle	Director	)	
Timothy P. Boyle		)	
		)	
/s/ Martha L. Byorum	Director	)	
Martha L. Byorum		)	
		)	
/s/ John D. Carter	Director	)	
John D. Carter		)	

		)	
/s/ Mark S. Dodson	Director	)	February 27, 2009
Mark S. Dodson		)	
		)	
/s/ C. Scott Gibson	Director	)	
C. Scott Gibson		)	
		)	
/s/ Tod R. Hamachek	Director	)	
Tod R. Hamachek		)	
		)	
/s/ Jane L. Peverett	Director	)	
Jane L. Peverett		)	
		)	
/s/ George J. Puentes	Director	)	
George J. Puentes		)	
		)	
/s/ Kenneth Thrasher	Director	)	
Kenneth Thrasher		)	
		)	
/s/ Russell F. Tromley	Director	)	
Russell F. Tromley		)	

Table of Contents

EXHIBIT INDEX

To

Annual Report on Form 10-K

For Fiscal Year Ended

December 31, 2008

Exhibit Number	Document
*3a.	Restated Articles of Incorporation, as filed and effective May 31, 2006 and amended June 3, 2008 (incorporated herein by reference to Exhibit 3a. to Form 10-K for 2006, File No. 1-15973).
*3b.	Bylaws as amended May 24, 2007 (incorporated herein by reference to Exhibit 3.1 to Form 8-K dated May 29, 2007, 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 the banks that are party thereto, with JPMorgan Chase Bank, N.A., as administrative agent and Bank of America, N.A., as syndication agent, dated as of May 31, 2007, including Form of Note (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated June 1, 2007, File No. 1-15973).
4i.(1)	Form of Letter Agreement, between each of JPMorgan Chase Bank, N.A., Bank of America, N.A., U.S. Bank National Association, UBS Loan Finance LLC, Wells Fargo Bank, N.A., Merrill Lynch Bank USA, dated as of April 29, 2008, extending the Credit Agreement between Northwest Natural Gas Company and each financial institutions with JPMorgan Chase Bank, N.A., as Administrative Agent.
*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).
*4m.	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. (Incorporated herein by reference to Exhibit 4j. to Form 10-K for 2006, File No. 1-5973).
*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.(1)	Replacement Firm Transportation Agreement, dated July 31, 1991, between the Company and Northwest Pipeline GP (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 GP 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).
*10j.(7)	Service Agreement Amendment, dated February 12, 2008, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(7) to Form 10-K for 2007, File No. 1-15973).

*10j.(8)	Service Agreement, dated February 8, 2008, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(8) to Form 10-K for 2007, File No. 1-15973).
*10j.(9)	Agreement between the Company and March Point Cogeneration Company, dated February 8, 2008 (incorporated herein by reference to Exhibit 10j.(9) to Form 10-K for 2007, File No. 1-15973).
10j.(10)	Firm Transportation Service Agreement, dated October 22, 1993, between the Company and Pacific Gas Transmission Company.
10j.(11)	Service Agreement (100310), dated January 21, 2008, between the Company and Northwest Pipeline GP.
10j.(12)	Service Agreement, dated January 21, 2008, between the Company and Northwest Pipeline GP.
10j.(13)	Service Agreement (Gas Storage Service), dated January 12, 1994, between the Company and Northwest Pipeline Corporation.
10j.(14)	Service Agreement (100309), dated January 21, 2008, between the Company and Northwest Pipeline GP.
10j.(15)	Service Agreement (100308), dated January 12, 1994, between the Company and Northwest Pipeline GP.
10j.(16)	Service Agreement, dated January 20, 1995, between the Company and NOVA Gas Transmission Ltd.
10j.(17)	Service Agreement, dated November 1, 2004, between the Company and TransCanada PipeLines Limited.
10j.(18)	Service Agreement, dated October 24, 2008, between Foothills Pipe Lines Ltd. and the Company.
10j.(19)	Amendment and Restatement of Firm Transportation Service Agreement, dated November 1, 2004, between Terasen Gas Inc. and the Company.
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.
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:

*10b.	Executive Supplemental Retirement Income Plan (2007 Restatement) (incorporated herein by reference to Exhibit 10b to Form 10-K for 2007, File No. 1-15973).
*10b.(1)	Supplemental Executive Retirement Plan, effective September 1, 2004 restated December 20, 2007 (incorporated herein by reference to Exhibit 10b.(1) to Form 10-K

for 2007, 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).
*10c.	Restated Stock Option Plan, as amended effective December 14, 2006 (incorporated herein by reference to Exhibit 10c. to From 10-K for 2006, File No. 1-15973).
*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 February 26, 2009.
10f.	Directors Deferred Compensation Plan, effective June 1, 1981, restated as of February 26, 2009.
*10f.(1)	Deferred Compensation Plan for Directors and Executives effective January 1, 2005, restated February 28, 2008 (incorporated herein by reference to Exhibit 10f.(1) to Form 10-K for 2007, File No. 1-15973).
*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 Change in Control Severance Agreement between the Company and each executive officer.
*10o.-1	Severance agreement dated December 19, 2008 between the Company and Gregg S. Kantor (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 23, 2008, File No. 1-15973).
*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).
*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).
*10w.(2)	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10w.(2) to Form 10-K for 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).
*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).
*10bb.	Consent to Amendment of Deferred Compensation Plan for Directors and Executives, dated February 28, 2008 entered into by each executive officer (incorporated herein by reference to Exhibit 10bb to Form 10-K for 2007, File No. 1-15973).

* Incorporated herein by reference as indicated