NORTHWEST NATURAL GAS CO
Form 10-K
February 25, 2011

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, 2010

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 [X] No [ ]

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [X] No [ ]

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

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 the definitions of "large accelerated filer," "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, 2010, the registrant had 26,576,278 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 $1,144,884,863.

At February 22, 2011, 26,668,712 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, to be filed in connection with the 2011 Annual Meeting of Shareholders, are incorporated by reference in Part III.

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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.

Cost of gas sold: the delivered cost of natural gas sold to customers, including the cost of gas purchased or withdrawn from storage inventory, gains and losses from gas commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use.

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 reductions 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.

Interruptible service: natural gas service offered to customers (usually large commercial or industrial users) under contracts or rate schedules that allow for interruptions when necessary 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 and deliver natural gas 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 whereby a customer purchases both natural gas commodity supply and transportation from the 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 annually in average weather conditions.

Transportation service: service provided whereby a customer directly purchases natural gas commodity from a supplier but pays the utility to transport the gas over its distribution system to the customer's facility.

Demand cost: 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.

Utility margin: utility gross revenues less the associated cost of gas sold 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.

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Forward-Looking Statements

This report contains "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. Forward-looking statements can be identified by words such as "anticipates," "intends," "plans," "seeks," "believes," "estimates," "expects" and similar references to future periods. Examples of forward-looking statements include, but are not limited to statements regarding the following:

- plans;
- objectives;
- goals;
- strategies;
- future events or performance;
- trends;
- cyclicality;
- earnings and dividends;
- growth;
- customer rates;
- commodity costs;
- operational performance and costs;
- liquidity and financial positions;
- project development and expansion;
- competition;
- procurement and development of new gas supplies;
- liquefied natural gas;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- potential efficiencies;
- impacts of laws, rules and regulations;
- tax liabilities or refunds;
- outcomes and effects of litigation, regulatory actions, and other administrative matters;
- projected obligations under retirement plans;
- adequacy of, and shift in mix of, gas supplies;
- approval and adequacy of regulatory deferrals; and
- environmental, regulatory, litigation and insurance costs and recovery.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncer–tainties, risks and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements. We therefore caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements 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.

Any forward-looking statement made by us in this report speaks only as of the date on which it is made. Factors or events that could cause our actual results to differ may emerge from time to time, and it is not possible for us to predict all of them. We undertake no obligation to publicly update any forward-looking statement, whether as a result of new information, future developments or otherwise, except as may be required by law.

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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, and we have been doing business as NW Natural since September 1997. We maintain operations in Oregon, Washington and California and conduct businesses through NW Natural, its subsidiaries and joint ventures. A reference to NW Natural (“we,” “us” or “our”) in this report means NW Natural and its subsidiaries and joint ventures 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 that 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 segment or utility. Our local gas distribution segment 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 regional supply basins to our service territory, and reselling the gas to customers subject to rates, terms and conditions approved by the Public Utility Commission of Oregon (OPUC) or by the Washington Utilities and Transportation Commission (WUTC). Local gas distribution also includes transporting gas owned by customers from the interstate pipeline connection, or city gate, to the customers’ facilities for a fee, also approved by the OPUC or WUTC. In recent years, approximately 90 percent of our consolidated assets and consolidated net income have been 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 17 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 2010, we had approximately 674,000 utility customers, consisting of approximately 611,000 residential, 62,000 commercial and 1,000 industrial customers. Approximately 90 percent of our utility customers are located in Oregon and 10 percent are located 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 utility revenues.

See Note 4 to the Consolidated Financial Statements for further information on total assets and results of operations for the years ended December 31, 2010, 2009 and 2008.

Utility Gas Supply, Storage and Transportation

We meet the expected needs of our core utility customers through natural gas purchases from a variety of suppliers. Our supply and delivery 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 transfer 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 are supplemented during periods of peak demand with gas from storage facilities either owned by or contractually committed to us.

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Gas Acquisition Strategy

Our goals in purchasing gas for our core utility customers 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 Year and Design Day Sendout";
- Lowest reasonable cost—Applying strategies to acquire gas supplies at the lowest reasonable cost for utility customers;
- Price stability—Making the best use of physical assets (e.g. gas storage and long-term gas reserves) and financial instruments (e.g. financial hedge contracts such as commodity price swaps and options) to manage commodity price volatility; 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, liquid trading points, price risk management strategies, 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 primarily from three key regional 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 continue to evaluate the long-term supply mix based on projections of gas production in the U.S. Rocky Mountain regions as well as other regions in North America. We believe that the cost of natural gas coming from western Canada and the U.S. Rocky Mountain regions will continue to track the broader U.S. market prices. Several pipeline projects have been built or are under construction to increase pipeline capacity out of the U.S. Rocky Mountain region. Additionally, new technology to extract shale gas resources has developed in recent years and has contributed to the increased availability of gas supply throughout North America. With the recent increase in North American gas supplies and current natural gas price levels, we do not foresee the need for a liquefied natural gas (LNG) import terminal in the Pacific Northwest at this time. Although LNG could provide an additional source of gas supply to the region with potentially competitive advantages, but based on current supply and demand outlook, we do not believe our region currently requires an LNG supply source.

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 supplies, non-heating season contracts where the supplier has the option to deliver gas to us on a daily basis, and seasonal purchase and sale exchange contracts. We try to maintain a diversified portfolio of purchase arrangements.

We also use a variety of multi-year contract durations to avoid re-contracting a majority of our supplies every year. See “Core Utility Market Basic Supply,” below.

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Liquid 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 multiple receipt points in the U.S. Rocky Mountains.

Price risk management strategies. Our four primary strategies for managing gas commodity price risk are:

- negotiating fixed prices either directly with gas suppliers or by purchasing long-term gas reserves;
- negotiating financial derivative instruments that effectively convert the floating price in a physical gas supply contract to a fixed price (referred to as commodity price swaps);
- negotiating financial derivative instruments that effectively set a ceiling or floor price, or both, on a floating price physical supply contract (referred to as commodity price options such as calls, puts, and collars); and
- buying gas and injecting it into storage or buying gas reserves for longer term supply deliveries. See "Cost of Gas Sold," 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 reduce our utility's cost of gas sold, and generates incremental revenues from a regulatory incentive sharing mechanism that are included in our gas storage business segment.

Regulatory alignment. Mechanisms for gas cost recovery are designed to be fair and to 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 sold, and we attempt to minimize risks associated with gas cost recovery through:

- re-setting customer rates annually for changes in forecasted gas costs and recovery of customer deferrals of prior year's actual versus forecasted gas costs (see Part II, Item 7., "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment");
- 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 Sold

The cost of gas sold to core utility customers primarily consists of the purchase price paid to suppliers, charges paid to pipeline companies to store and transport gas to our distribution system and gains or losses related to gas 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 ebbed and flowed over the last several years primarily due to shifts in the balance of supply and demand, which has been affected by a variety of factors, including weather, customer growth, the level of production and availability of natural gas, imports of natural gas, transportation constraints, availability of pipeline capacity, transportation capacity cost increases, federal and state energy and environmental regulation and legislation, the degree of market liquidity, supply disruptions, national and worldwide economic and political conditions, and the price and availability of alternative fuels. With recent success in new drilling technologies and substantial new supplies from shale gas formations around the U.S. and in Canada, the supply of North American natural gas has increased dramatically, which has contributed to a trend of lower gas prices. Additionally, we are in a favorable geographic 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 growth in gas production is expected to continue for the foreseeable future.

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Transportation cost. Pipeline transportation rates charged by Canadian pipelines and U.S. interstate pipeline transportation service providers have been relatively stable over the last several years, due in part to 2006 rate case settlement provisions for the U.S. interstate pipelines. These rates periodically change when the Canadian pipelines and U.S. interstate pipelines file for rate change approval from the Canadian National Energy Board or Federal Energy Regulatory Commission (FERC), as applicable. Pipeline transportation rate increases or decreases are generally passed on to our customers through annual PGA updates.

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 in an attempt to fix or limit the price of gas commodity purchases. Realized gains or losses from financial commodity hedge contracts are treated as reductions or increases to the cost of gas sold.

Managing the Cost of Gas Sold

We manage natural gas commodity price risk through active physical and financial hedging programs. The intent of these hedging programs is to manage the price exposure for a majority of our gas supply portfolio for the following gas contract year, which begins November 1 of each year. 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 are allowed to enter into commodity swaps, puts, calls and collars with terms generally ranging anywhere from one month to five years.

In addition to the prices that are hedged through financial contracts, we also own physical gas supplies in storage. We purchase and inject gas into storage during the summer months when demand and gas prices are generally lower. About 15 percent of our annual gas supply requirements 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 reduces the need for additional upstream pipeline capacity and provides cost savings and price stability. The other two storage facilities are owned and operated by our primary pipeline supplier.

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 and include a three day design peak event that is based on the coldest weather experienced over the last 20 years in our service territory. 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 9.1 million therms. Of this total, we are currently capable of meeting nearly 60 percent of our firm customer maximum design day requirements with gas from storage located within or adjacent to our service territory, while the remaining gas supply requirements would be met by gas purchases under firm and recall gas purchase contracts. Optimal utilization of storage 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 that confirmed our load forecasting models required very little re-calibration. Similar cold temperatures experienced in December 2008 and December 2009 produced very high sendout days, but firm sendout in December 2009 was still about 3 percent below our 2004 record. Accordingly, we believe that our supplies would be sufficient to meet existing firm customer demand if we were to experience design day weather conditions. We will continue to evaluate and update our forecasted requirements and incorporate changes in our integrated resource plan (IRP) process (see “Integrated Resource Plan,” below).

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The following table shows the sources of supply that are projected to be used to satisfy the design day sendout for the 2010-2011 winter heating season:

Projected Sources of Utility Supply for Design Day Sendout

Sources of Utility Supply	Therms (in millions)	Percent
Firm supply purchases	3.3	37
Mist underground storage (utility only)	2.5	27
Company-owned LNG storage	1.8	20
Off-system firm storage contracts	1.1	12
Recall agreements	0.4	4
Total	9.1	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 core utility customers and positions the utility to meet future requirements.

Core Utility Market Basic Supply

We purchase natural gas for our core utility customers from a variety of suppliers located in western Canada and the U.S. Rocky Mountain areas. Currently, about 60 percent of our supply comes from Canada, with the balance coming primarily from the U.S. Rocky Mountain region. At December 31, 2010, we have contracts with gas suppliers for deliveries ranging from three months to four years, which provide for a maximum of 2.2 million therms of firm gas per day during the winter heating season and 0.6 million therms per day during the entire year. These contracts have a variety of pricing structures and purchase obligations. In addition, we have another 1.1 million therms per day of firm gas supplies whereby we can purchase contract or spot gas supplies for delivery to our system during the winter heating season. During 2010, we purchased a total of 715 million therms of gas under contracts with the durations outlined in the chart below.

Contract Duration (primary term)	Percent of Purchases
Long-term (one year or longer)	39
Short-term (more than one month, less than one year)	26
Spot (one month or less)	35
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), no individual supplier provided more than 10 percent of our supply requirements. Firm year-round supply contracts have remaining terms ranging from one to four years. Currently, all firm gas supply contracts use price formulas tied to monthly index prices. We hedge a majority of these contracts each year using financial derivative instruments as part of our gas purchasing strategy (see “Managing the Cost of Gas Sold,” above).

In addition to our 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 2010, new short-term purchase contracts were entered into with 21 suppliers, which in addition to our year round contracts provide for a total of up to 2.2 million therms per day during the 2010-2011 heating season. We intend to enter into new purchase contracts during 2011 for roughly the same volume of gas with existing or new suppliers, as needed, to replace contracts that will expire in 2011.

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We also buy gas on the spot market as needed to meet utility customer demand. We have flexibility under the terms of some of our firm supply contracts, which enables us to purchase spot gas in lieu of the firm contract volumes thereby allowing us to take advantage of more 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 facilities. Current production supplies are less than 1 percent of our total annual purchase requirements. Production from these wells varies as existing wells are depleted and new wells are drilled.

Core Utility Market Peaking Supply and Storage

We supplement our firm gas supply purchases with gas withdrawals from storage facilities we own or that are contractually committed to us. Gas is generally purchased and injected into storage during periods of low demand so that it can be withdrawn 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 capacity 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 core utility customers from our underground gas storage facility in the Mist gas storage field. Including the latest expansions in 2009, this facility has a maximum daily deliverability of 5.2 million therms and a total working gas capacity of about 16 Bcf. In May 2009, a total of 100,000 therms per day of Mist storage capacity that had previously been available for non-utility gas storage services was recalled and committed to use for core utility customers. This was the first recalled capacity since 2004. There was no Mist recall in 2010, but 100,000 therms per day is planned for recall in May 2011. Under our regulatory agreement with the OPUC, non-utility gas storage at Mist was developed in advance of core utility customer needs but can be recalled by the utility to serve utility customers as utility demand increases. Storage capacity recalled by the utility is added to utility rate base at net book value and tracked into utility rates in the annual PGA filing immediately following the recall, so there is minimal regulatory lag in cost recovery. The core utility currently has 2.5 million therms per day of deliverability and approximately 9.4 Bcf of working gas capacity committed from the Mist storage facility.

We also have contracts with the Williams Companies' Northwest Pipeline (Northwest Pipeline) for firm gas storage from an underground facility at Jackson Prairie near Chehalis, Washington, and from an LNG facility in 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 storage. 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 periods of peak demand in the winter heating season. These two facilities provide a maximum combined daily deliverability of 1.8 million therms and a total seasonal capacity of 16 million therms.

Recallable capacity from transportation customers. We also have contracts with one electric generator and two industrial customers that together provide 390,000 therms per day of recallable pipeline capacity and supply.

Transportation

Single transportation pipeline. Our local gas distribution system is directly connected to a single interstate transmission pipeline, Northwest Pipeline. Although we are dependent on a single pipeline, the pipeline's gas flows are bi-directional and, as such, gas is transported into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the 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 jointly developing plans to build a pipeline (Palomar) that would connect TransCanada Pipelines Limited's (TransCanada) Gas Transmission Northwest (GTN) interstate transmission line to our local 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 another transportation path for gas purchases from Alberta and the U.S. Rocky Mountains in addition to the one that currently moves gas through the Northwest Pipeline system (See Part II, Item 7., "2011 Outlook—Strategic Opportunities—Pipeline Diversification").

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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. Application to extend this contract through September 2018 has been filed with FERC and is pending approval. 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 with Northwest Pipeline and GTN systems in eastern Oregon to our service territory. Application to extend this contract through November 2016 has been filed with FERC and is pending approval. 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 extends into 2044 for approximately 350,000 therms per day of firm transportation capacity from the U.S. Rocky Mountain region. Additionally, in 2008 we executed an agreement with a third party to take assignment of their firm transportation contract starting January 1, 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 580,000 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 480,000 therms per day of firm 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 systems in British Columbia and Alberta, allowing purchases to be made from the gas fields of Alberta, Canada.

Rates. FERC establishes rates for interstate pipeline transportation service under long-term agreements within the U.S., and Canadian authorities establish rates for service under agreements with the Canadian pipelines over which we ship gas.

Integrated Resource Plan

The OPUC and WUTC have integrated resource planning processes (IRP) in which utilities define different growth scenarios and corresponding resource acquisition strategies in an effort to:

- Evaluate supply and demand resources;
- Consider uncertainties in the planning process and the need for flexibility to respond to changes; and
- Establish a plan for getting reliable service at the "least cost".

In general, the IRP is filed biannually with both the OPUC and the WUTC. An annual update is filed in Oregon in the off year. The OPUC acknowledges the IRP; whereas the WUTC provides notice that our IRP met the requirements of the Washington Administrative Code. Commission acknowledgment of the IRP does not constitute ratemaking approval of any specific resource acquisition strategy or expenditure. However, 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. We filed our 2011 IRP in Oregon in January 2011 and expect to file our IRP in Washington in March 2011.

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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 energy suppliers is based on price, efficiency, reliability, performance, market conditions, technology, legislative policy, and environmental impact. 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 sold 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 less than 60 percent, and our operating convenience and environmental advantage over fuel oil, provides the potential for continuing growth from residential and commercial conversions. In 2010, 5,906 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 2010 was 6,203. This represents a 12-month growth rate of 0.9 percent, which is up slightly from 2009 but still well below historical growth rates due to the slow economic recovery and weak job market.

On an annual basis, residential and commercial customers typically account for about 55 to 60 percent of our utility's total volumes delivered and about 85 to 90 percent of gross operating revenues, while industrial customers account for about 40 to 45 percent of volumes and about 10 percent of gross operating revenues. The remaining gross operating revenues are derived from miscellaneous services and other regulatory revenues.

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 customer businesses 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 industrial 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 are priced at our sales service rate less the commodity cost included in that rate. Therefore, our transportation margins (i.e. sales minus the cost of gas sold) are generally unaffected financially if industrial customers buy commodity supplies directly from producers or marketers rather than purchasing gas from us, as long as they remain on a tariff or contract with the same level 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 as well as other levels of service, and these choices can positively or negatively affect margin. That is, firm service has a higher profit margin than interruptible service. 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.

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Our industrial tariffs include terms which are intended to give us more certainty in the level of gas supplies we will need to purchase in order to serve this customer group. The terms include an annual election cycle period, special pricing provisions for out-of-cycle changes and the requirement that industrial customers on our annual weighted average PGA tariff must 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 in accordance with our regulatory tariff.

We have designed custom transportation service agreements with several of our largest industrial customers. These agreements are primarily 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 local 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.

Gas Storage

Our gas storage segment primarily consists of two underground natural gas storage facilities, including the non-utility portion of our Mist gas storage facility near Mist, Oregon and our portion of the Gill Ranch gas storage facility (Gill Ranch Storage, LLC or Gill Ranch) near Fresno, California. Because transmission pipeline capacity and natural gas production are relatively flat over the course of a year compared to the demand for natural gas, which fluctuates daily and seasonally, natural gas storage facilities are needed to manage the flow and availability of gas supplies during periods of low demand so these supplies can be stored and delivered into markets during periods of high demand. We capitalize on the imbalance of supply and demand for natural gas by providing our gas storage customers with the ability to store gas for resale or use in a higher value period. Our natural gas storage facilities allow us to offer customers "multi-cycle" storage service, which permits them to inject and withdraw natural gas multiple times a year, providing more flexibility to capture market opportunities.

Facilities

Mist Gas Storage Facility

We provide gas storage services to customers in the interstate and intrastate markets from our Mist gas storage facilities located in Columbia County, Oregon, near the town of Mist. In 1989, the Mist storage field began storage operations for our core local gas distribution customers. Since 2001, we have made excess gas storage capacity at Mist available to interstate customers, and we have developed new gas storage capacity at Mist in advance of core utility customer requirements to meet the additional demands for interstate storage service. These interstate storage services are offered under a limited jurisdiction blanket certificate issued by FERC. In addition, since 2005 we have offered firm storage service in Oregon under an OPUC-approved rate schedule as an optional service to eligible non-residential utility customers. Currently, the Mist facilities consist of seven depleted natural gas reservoirs with a combined working gas capacity of 16 Bcf, a combined deliverability of approximately 520,000 Dth/day, a central compression facility, gathering pipelines and other related facilities.

In addition to earning revenue from customer storage contracts, we also use an independent energy marketing company to provide asset optimization services for utility and non-utility storage and transportation capacity under a contractual arrangement, the results of which are included in the gas storage business segment. 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.

Gill Ranch Gas Storage Facility

Gill Ranch, our subsidiary, has a joint project agreement with Pacific Gas and Electric Company (PG&E) to develop, own and operate an underground natural gas storage facility near Fresno, California. Gill Ranch holds a 75 percent undivided ownership interest in this facility. The construction of this facility began in January 2010, and a majority of the construction work was completed by October 2010. The facility began operations during the fourth quarter of 2010. Gill Ranch is the sole operator of the facility.

The Gill Ranch storage facility currently consists of three depleted natural gas reservoirs, twelve injection and withdrawal wells, a compressor station, dehydration and control equipment, gathering lines, an electric substation, a natural gas pipeline that extends approximately 27 miles from the storage field to an interconnection with the PG&E transmission system, and other related facilities. We have rights to 75 percent of the available storage capacity at Gill Ranch. Our share of the working gas capacity is designed to be approximately 15 Bcf, which we expect to achieve by the end of 2013.

Gill Ranch is offering storage services to the California market at market-based rates, subject to the California Public Utilities Commission (CPUC) regulation of certain activities including, but not limited to, service terms and conditions, tariff regulations, and security issuances.

Assets. The following table highlights certain important design information about our non-utility gas storage assets.

	Storage Capacity (Bcf)	Withdrawal (MMcf/day) [3]	Injection (MMcf/day) [3]
Mist Gas Storage	7 [1]	265	106
Gill Ranch Storage	15 [2]	488	240

1. Approximately 7 Bcf of Mist storage capacity is currently available to our gas storage segment. The remaining 9 Bcf is used to provide gas storage services to the utility.
2. Total capacity for our share of the Gill Ranch facility is designed to be approximately 15 Bcf by the end of 2013.
3. Expected maximum injection and withdrawal rates.

Gas Storage Operations

Asset optimization. With respect to the Mist gas storage facility, we contract with an independent energy marketing company to optimize the value of our utility pipeline transportation contracts, our utility gas supplies and our unused utility and non-utility storage assets, primarily through the use of commodity transactions and pipeline capacity release transactions (see “Facilities—Mist Gas Storage Facility,” above). We contract with the same independent energy marketing company to optimize the value of our unused storage assets at our Gill Ranch gas storage facility (see “Facilities—Gill Ranch Gas Storage Facility,” above). The results of asset optimization at both facilities are included in the gas storage business segment, except for amounts allocated to the utility pursuant to a sharing agreement involving the use of utility assets.

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

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Although we expect much of the storage revenue at Gill Ranch to be in the form of fixed monthly demand charges, we expect that total cash flows from the Gill Ranch storage facility may be, at least initially, more seasonal in nature than the Mist storage facility. We expect that in the initial years of operation of Gill Ranch a relatively greater percentage of the capacity will be optimized by the independent energy marketing company with whom we contract than is the case with Mist, resulting in greater seasonality of revenue for that activity, which usually occurs more often in the winter months. A significant portion of operating costs at Gill Ranch will include the energy and demand charges for electricity used to drive the compressors. Because compression is used primarily for the injection of gas rather than for withdrawal, we expect power costs to be incurred disproportionately in the months of April through October.

Gas storage customers. For our Mist interstate storage services, firm service agreements with customers are entered into with terms typically ranging from one to 10 years. Currently, our gas storage revenues from Mist are derived primarily from firm storage service customers who provide energy related services, including natural gas distribution, electric generation and energy marketing. Three storage customers currently account for over 85 percent of our existing non-utility gas storage capacity at Mist, with the largest customer accounting for about half of total capacity. These three customers have contracts that expire at various dates through April 2017.

Customer contracts for firm storage capacity at Gill Ranch are as long as 28 years in duration but, our intent in the early phases of operation, is to contract for terms ranging from one to seven years duration. We currently have several storage contracts, with the largest single contract accounting for approximately 13 percent of our design capacity; however, we are in a start-up period and have not contracted for the full 2011-2012 contract year. Moreover, the California market served by Gill Ranch is larger and has a greater diversity of prospective customers than the Pacific Northwest market served by Mist. As such, we expect there to be less sensitivity to any single or fewer set of customers for Gill Ranch. Current storage customers provide energy related services, including natural gas marketing and electric generation.

Competitive conditions. Our Mist gas storage facility benefits from limited competition from other Pacific Northwest storage projects primarily because of its geographic location. However, competition from other storage providers in the Pacific Northwest region and Canada, as well as competition for interstate pipeline capacity, does exist. In the future, we could face increased competition from new or expanded gas storage facilities as well as from new natural gas pipelines, marketers and alternative energy sources.

Our Gill Ranch storage facility competes with a number of other storage providers, including local integrated gas companies and other independent storage operators in the northern California gas storage market. There is also ongoing development and proposed new construction of storage capacity and expansions in northern California that could increase competition for Gill Ranch.

Interstate gas storage. The Mist gas storage facility currently provides firm and interruptible gas storage services with related transportation services on the utility's system to and from Mist to interstate pipeline interconnections in order to serve customers in interstate commerce. The interstate storage services, and maximum rates for these services, are authorized and regulated 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.

We do not expect the Gill Ranch storage facility to provide, nor is it currently authorized to provide, interstate gas storage services.

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

The Gill Ranch storage facility provides intrastate storage services in California at market-based rates under a CPUC-approved tariff that includes firm storage service, interruptible storage service and park and loan storage services.

Storage Expansions.

Mist Storage Facility. While the Pacific Northwest storage markets have been negatively impacted by lower gas prices and lack of price volatility, albeit less so than in California, we continue to plan for expansion at our gas storage facilities near Mist, Oregon but currently do not have a set timeline for development. We believe the earliest timeframe for moving forward with the next expansion is 2013. In the meantime, we expect to continue working on preliminary design and project scope, which will likely include the development of storage wells, potentially a second compression station and additional pipeline gathering facilities that would enable future storage expansions.

Gill Ranch Storage Facility. Subject to market demand, project execution, available financing, receipt of future permits, and other rights, we have the operational capacity to expand the Gill Ranch facility beyond our and PG&E's combined permitted capacity of 20 Bcf, without further expansion of our takeaway pipeline system. Taking these considerations into account and with certain infrastructure modifications, we currently estimate that the Gill Ranch storage facility could support an aggregate storage capacity of around 40 Bcf, of which we would have the rights to an aggregate of 20 Bcf or 50 percent of total estimated storage capacity.

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 because these 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., "2011 Outlook—Strategic Opportunities—Pipeline Diversification," below), a minority interest in other pipeline assets held by our wholly-owned subsidiary NNG Financial, as well as other operating and non-operating expenses of the parent company that cannot be charged to utility operations. Less than 1 percent of our consolidated assets and consolidated net income are related to activities in the "Other" business segment. See Note 4 for more information on total assets and results of operations for the three years ended December 31, 2010.

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, the FERC and, with respect to Gill Ranch, the CPUC. The OPUC and WUTC also regulate our issuance of securities, as does the CPUC with respect to Gill Ranch. Approximately 90 percent of our utility operating revenues are derived from Oregon customers, and the balance is derived from Washington customers.

We file general rate case and rate tariff requests with the OPUC, WUTC and FERC to periodically change the rates we charge our utility and storage customers. Gill Ranch has a tariff on file with the CPUC and is authorized to charge market-based rates for the storage services offered under such tariff. 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 in December 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 to file every five 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. For further information, see Part II, Item 7., "Results of Operations—Regulatory Matters," below and "Business Segments—Gas Storage," above.

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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 certain environmental impacts. 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 (EPA) 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 holding tanks (Central 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 15 for a further discussion of potential environmental responses, related costs and regulatory and insurance recovery.

Greenhouse Gases Issues

We recognize that our businesses are likely to be impacted by carbon constraints. A variety of legislative and regulatory measures to address greenhouse gas emissions are in various phases of discussion or implementation. These include proposed international standards, proposed federal legislation, proposed or enacted federal regulations, and proposed or enacted state actions to develop statewide or regional programs, each of which has imposed or would impose measures to achieve reductions in greenhouse gas emissions. For example, in December 2009, the EPA published its findings that concentrations of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment as drivers of climate change, and that emissions from motor vehicles contribute to that threat. Based on these findings by the EPA, the agency proceeded with the adoption and implementation of regulations to regulate emissions of greenhouse gases starting in January 2011 from new motor vehicles and from stationary sources of air pollution such as power plants and oil refineries. One of these new regulations, which the EPA refers to as the "Tailoring Rule," requires that permits held by larger sources of air pollution address greenhouse gases, and also requires additional permitting and implementation of best available control technology for limiting greenhouse gas emissions at certain new facilities and at existing facilities when they implement modifications that increase emissions of greenhouse gases above threshold levels. Lawsuits have been filed challenging the EPA's regulation of greenhouse gas emissions and members of the U.S. Congress have discussed proposing legislation that would limit the EPA's ability to regulate greenhouse gas emissions.

In September 2009, the EPA issued a final rule requiring the annual reporting of greenhouse gas emissions from certain industries, specified large greenhouse gas emission sources, and facilities that emit 25,000 metric tons or more of CO_2 equivalents per year. The first reports are due by March 31, 2011 for emissions occurring on or after January 1, 2010.   Under this reporting rule, local gas distribution companies are required to report system throughput to the EPA on an annual basis. The EPA also issued additional greenhouse gas reporting regulations in November 2010 requiring the annual reporting of fugitive emissions from our operations. The first report under these more recent regulations is due by March 31, 2012.

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The outcome of these and other international, 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, legal actions, additional charges to fund energy efficiency activities, or other regulatory actions. The adoption and implementation of any regulations limiting emissions of greenhouse gases from our operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations, which could result in an increase in the prices we charge our customers or a decline in the demand for natural gas. On the other hand, because natural gas is a fossil fuel with relatively low carbon content, it is also possible that future carbon constraints could create additional demand for natural gas for electric production, direct use in homes and businesses and as a reliable and relatively low-emission back-up fuel source for alternative energy sources.

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. 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, 2010, our workforce employed by NW Natural consisted of 607 members of the Office and Professional Employees International Union (OPEIU), Local No. 11, AFL-CIO, and 421 non-union employees. Our labor agreement with members of OPEIU that covers wages, benefits and working conditions extends to May 31, 2014, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement.

NW Natural Gas Storage, LLC (NWN Gas Storage) is our only subsidiary that currently has employees. Its workforce currently consists of 19 non-union employees. NWN Gas Storage receives certain services from NW Natural, and as such reimburses NW Natural for those services pursuant to a Shared Services Agreement. Gill Ranch also receives certain services under a similar agreement with NW Natural.

Additions to Infrastructure

We make capital expenditures in order to maintain and enhance the safety and integrity of our pipelines, terminals, storage facilities and related assets, to expand the reach or capacity of those assets, or improve the efficiency of our operations to pursue new business opportunities. We expect to make a significant level of capital expenditures for additions to utility and gas storage infrastructure over the next five years, reflecting continued investments in customer growth, technology, distribution system enhancements and gas storage facilities. In 2011, utility capital expenditures are estimated to be between $95 and $105 million, and non-utility capital investments are estimated to be between $5 and $15 million. For the years 2011-2015, capital expenditures for the utility are estimated to be between $400 and $500 million, while the amount for gas storage and other investments after 2011 will depend largely on future decisions about potential opportunities in gas storage and pipeline projects.

Executive Officers of the Registrant

For information concerning our executive officers, see Part III, Item 10.

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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 officers, 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, either code 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 at 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.

ITEM 1A. RISK FACTORS

Our business and financial results are subject to a number of risks and uncertainties, many of which are not within our control. When considering any investment in our securities, investors should carefully consider the following information, as well as information contained in the caption “Forward Looking Statements,” Item 7A., and other documents we file with the SEC. This list is not exhaustive and the order of presentation does not reflect management’s determination of priority or likelihood. Additionally, our listing of risk factors that primarily affect one of our business segments does not indicate that such risk factor is inapplicable to our other business segments.

Risks Related to our Business Generally

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

Changes in economic activity in our markets and in global financial markets can result in a decline in energy consumption, which could have a negative effect on our financial condition and results of operations. In recent years, the U.S. and world economies have slowed, credit markets have tightened, unemployment rates and mortgage defaults have risen, and the value of homes and other personal as well as business investments have declined, which has adversely affected the income and financial resources of many domestic households and businesses. It is unclear whether the federal responses to these conditions will lessen the severity or duration of this economic downturn, or could possibly trigger inflationary conditions. Our operations and financial results are affected by these economic conditions. Less new housing construction, fewer conversions to natural gas, fewer customer additions, higher levels of residential foreclosures and vacancies, higher borrowing rates, and personal and business bankruptcies or reduced spending could all result in a decline in energy consumption and customer growth, a slowing of collections from our customers, and a higher than normal level of accounts receivable and bad debts, all of which could have a negative effect on our financial condition and results of operations.

Regulatory risk. Regulation of our businesses, 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 the rates charged to customers, authorized rates of return on capital invested, the amounts and types of securities we may issue, services we provide, facilities we own or operate, terms of customer services, system of accounts, the nature of investments we may make, safety standards, deferral and recovery of various expenses, including, but not limited to, pipeline replacement and environmental remediation costs, transactions with affiliated interests, actions investors may take with respect to our company and other matters. Similarly, FERC has regulatory authority over our interstate gas storage services, and the CPUC has regulatory authority over our Gill Ranch gas storage operations.

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The rates we charge to customers must be approved by the applicable regulatory agencies. Our utility and gas storage 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, the rates charged to customers of Gill Ranch for gas storage services are based on negotiated rates (i.e. market-based rates) rather than on our recovery of costs plus a reasonable return on our investment (i.e. cost-based rates). We expect to continue to make expenditures to expand, improve and operate our utility distribution and gas storage systems. Regulators can deny such expansions or improvements or 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 business we may place assets in service or incur higher than expected 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.

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.

Business development projects involve many risks. We are currently engaged in several business development projects, including the early planning and development stage on the Palomar gas transmission pipeline in Oregon and the final completion of the first phase of construction at the Gill Ranch gas storage facility in California. We may also engage in other business development projects in the future, including expansion of our gas storage facilities at Mist or Gill Ranch or the investment in long-term gas reserves. 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 customer demand, public opposition to projects, changes in market prices, and operating cost increases. Additionally, natural gas storage and transportation markets are highly competitive, both within the natural gas industry and with alternative sources of energy. To fund our business development projects, we will need to secure financing from willing investors at reasonable costs. If credit markets are inaccessible, we may be unable to finance our business development projects at acceptable interest rates or within a scheduled timeframe for completing the project. Similarly, an inability to obtain the necessary state permits, or arrange for sufficient supplier commitments could impact the viability of the Palomar pipeline. 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 and results of operations.

Joint partner risk. Investing in business development projects through partnerships, joint ventures or other business arrangements decreases our ability to manage certain risks and could adversely impact our financial condition, results of operations and cash flows.

We use joint ventures and other business arrangements to manage and diversify the risks of certain utility and non-utility development projects, including Palomar and Gill Ranch, and we may acquire interests in other similar 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 including making operational decisions that could affect our costs and liabilities related to a project. 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 the project as well as our financial condition, results of operations and cash flows.

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Global climate change risk. Management expects that future legislation may impose carbon constraints to address global climate change exposing us to regulatory and financial risk. Additionally, certain properties and facilities may be subject to physical risks associated with climate change.

There are a number of new international, federal and state legislative and regulatory initiatives being proposed and adopted in an attempt to measure, control or limit the effects of global warming and overall climate change, including greenhouse gas emissions such as carbon dioxide. The adoption of current or future proposed legislation by the U.S. Congress or similar legislation by states, or the adoption of related regulations by federal or state regulatory bodies such as the EPA, imposing reporting obligations on, or limiting emissions of greenhouse gases from our equipment or operations could have far-reaching and significant impacts on our business as well as the broader energy industry. Such current or future legislation or regulation could also impose on us operational requirements or restrictions or additional charges to fund energy efficiency initiatives. Such initiatives could result in us incurring additional costs to comply with the imposed restrictions, provide a cost advantage to energy sources other than natural gas, reduce demand for natural gas, impose costs or restrictions on end users of natural gas, impact the prices we charge our customers, impose on us increased costs associated with the adoption of new infrastructure and technology to respond to such requirements, and may impact cultural perception of our service or products negatively, diminishing the value of our brand, all of which could adversely affect our business practices, financial condition and results of operations.

Climate change may cause physical risks, including an increase in sea level, intensified storms, water scarcity and changes in weather conditions, such as changes in precipitation, average temperatures and extreme wind or other climate conditions. A significant portion of the nation's gas infrastructure is located in areas susceptible to storm damage that could be aggravated by wetland and barrier island erosion, which could give rise to gas supply interruptions and price spikes.

These and other physical changes could result in changes in customer demand, increased costs associated with repairing and maintaining distribution systems resulting in increased maintenance and capital costs, increased financing needs, limits on our ability to meet peak customer demand, increased regulatory oversight, and lower customer satisfaction. Also, to the extent that climate change adversely impacts the economic health of our region, it may adversely impact customer demand and revenues. Such physical risks could have an adverse effect on our financial condition, results of operations, and cash flows.

Operating risk. Transporting and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs, some or all of which may not be fully covered by insurance, and which could adversely affect our financial condition, results of operations and cash flows.

Our operations are subject to all of the risks and hazards inherent in the businesses of natural gas distribution and storage, including:

- earthquakes, floods, storms, landslides and other adverse weather conditions and hazards;
- leaks or other losses of natural gas or other hydrocarbons as a result of the malfunction of equipment and facilities;
- damages from third parties, including construction, farm and utility equipment or other surface users;
- operator errors;
- negative unpredicted performance by our storage reservoirs that could cause us to fail to meet expected or forecasted operational levels or contractual commitments to our customers;
- problems maintaining, or the malfunction of, pipelines, wellbores and related equipment and facilities that form a part of the infrastructure that is critical to the operation of our gas distribution and storage facilities;
- collapse of storage caverns;

- migration of natural gas through faults in the rock or to some area of the reservoir where existing wells cannot drain the gas effectively;
  - blowouts (uncontrolled escapes of gas from a pipeline or well) or other accidents, fires and explosions; and
- risks and hazards inherent in the drilling operations associated with the development of the gas storage facilities and/or wells.

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These risks could result in personal injury or loss of human life, damage to and destruction of property and equipment, pollution or other environmental damage, breaches of our contractual commitments, and may result in curtailment or suspension of our operations, which in turn could lead to significant costs and/or lost revenues. Further, because our pipeline, storage and distribution facilities are in or near populated areas, including residential areas, commercial business centers, and industrial sites, any loss of human life or adverse financial results resulting from such events could be significant. Natural gas that moves outside of the effective drainage area through migration could be permanently lost and will need to be replaced. Additionally, we may not be able to obtain the level or types of insurance we desire, and the insurance coverage we do obtain may contain large deductibles or fail to cover certain hazards or cover all potential losses. The occurrence of any operating risks not covered by insurance could adversely affect our financial condition, results of operations and cash flows.

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

Local or national disasters, pandemic illness, terrorist activities and other extreme events are a threat to our assets and operations. Companies in our industry may face a heightened risk due 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. Local disaster or pandemic illness could result in part of our workforce being unable to operate or maintain our infrastructure or perform other tasks necessary to conduct our business. We maintain emergency planning and training programs to remain ready to respond to events that could cause business interruption. However, a slow or inadequate response to events may have an adverse impact on operations and earnings. We may not be able to obtain sufficient insurance to cover all risks associated with local and national disasters, pandemic illness, terrorist activities and other 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 assets and liabilities, changing employee demographics and changing actuarial assumptions, which may have an adverse effect on our financial condition.

We provide pension plans and postretirement healthcare benefits to most eligible full-time employees and retirees. Our cost of providing such benefits is subject to changes in the market value of our pension assets, changes in employee demographics, including longer life expectancies of beneficiaries, increases in healthcare costs, current and future legislative changes, including but not limited to the Health Care Reform Act in 2010, and various actuarial calculations and assumptions. The actuarial assumptions used to calculate our future pension and postretirement healthcare expense may differ materially from actual results due to significant market fluctuations and changing withdrawal rates, wage rates, interest rates and other factors. These differences may result in an adverse impact on the amount of pension contributions, pension expense or other postretirement benefit costs recorded in future periods. Sustained declines in equity markets and reductions in bond prices 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 financial condition, results of operations and cash flows.

Workforce risk. Our business is heavily dependent on being able to attract and retain qualified employees and 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 business strategy and serve our customers 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 and meet our regulatory requirements will be challenged and this could negatively impact our earnings. Additionally, within our utility segment a majority of our workers are represented by the 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, 2014. Disputes with the Union over terms and conditions of the agreement could result in instability in our labor relationship and work stoppages that could impact the timely delivery of gas and other services from our utility and Mist gas storage, which could strain relationships with customers and state regulators and cause a loss of revenues which could adversely affect our results of operations. Our collective bargaining agreement may also increase the cost of employing our utility segment 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 in today’s challenging marketplace.

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Legislative and taxing authority risk. We are subject to governmental regulation, and 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 law required that utilities not collect in rates more income taxes than they actually pay to taxing authorities. If amounts paid differ from amounts collected by more than $100,000, then we are required to implement a rate schedule with an automatic adjustment to refund or collect the difference.

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 result in substantial cost to us and negatively affect our results of operations. Tax law and its related regulations and case law are inherently complex and dynamic. 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 taxing authorities. Changes in laws, regulations or adverse judgments may negatively affect our financial condition and results of operations.

Environmental regulation risk. We are subject to environmental regulations which could adversely affect our operations or financial results.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety.

Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Failure to comply with these laws, regulations, permits and licenses may expose us to fines, penalties or interruptions in our operations that could adversely affect our financial results. In addition, existing environmental regulations may be revised or our operations may become subject to new regulations, which could negatively affect our financial condition and results of operations.

Environmental liability risk. Certain of our properties and facilities may pose environmental risks requiring remediation, the cost of which could adversely affect our financial condition, results of operations 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 at the utility has already been recorded for estimated costs pursuant to a deferral order from the OPUC. To the extent we are unable to recover these deferred costs in utility customer rates or through insurance, we would be required to reduce our regulatory asset which would adversely affect our results of operations and financial condition. 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 associated costs and uncertain outcomes.

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We cannot predict with certainty the amount or timing of future expenditures related to environmental investigation and remediation that may be required, or disputes arising in relation thereto, 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. Moreover, there are 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 financial condition and results of operations, particularly if those costs are not fully recoverable from insurance or through utility customer rates.

Safety regulation risk. We may experience increased federal, state and local regulation of the safety of our operations, which could adversely affect our operating costs and financial results.

We are committed to constantly monitoring and maintaining our pipeline and distribution system and storage operations to ensure that natural gas is stored and delivered safely, reliably and efficiently. The safety and protection of the public, our customers and our employees is our top priority. However, primarily due to the recent unfortunate pipeline incident in California, we anticipate companies with natural gas pipelines may be subject to even greater federal, state and local oversight over the safety of their operations in the future. Accordingly, the costs of complying with such increased regulations may have an impact on our future capital and operating costs and ultimately our financial results.

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, which could result in an adverse impact on our operating revenues, costs, derivative assets and liabilities and operating cash flows.

In our utility segment, 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, liquidity and other financial market risks. We attempt to manage these exposures and mitigate our risks through adherence to established risk limits and risk management procedures, including hedging activities that are in accordance with our derivatives policy guidelines. 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 adversely impact our financial condition, results of operations, and cash flows.

We 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 an adverse effect on our financial condition and results of operations. 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 than we anticipated. Moreover, if our derivative instruments and hedging transactions do not qualify for hedge accounting under generally accepted accounting standards, our hedges may not be effective and our results of operations and financial condition could be adversely affected.

We also have credit-related exposure to derivative counterparties. In general, we require our counterparties to have an 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 and the potential loss due to a default by our counterparties, an actual default by a particular counterparty could have a greater impact than we estimate. Additionally, under most of our hedging arrangements, any downgrade of our senior unsecured long-term debt credit rating 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 borrowing from our credit facilities if the credit rating downgrade is below investment grade.

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Inability to access capital market risk. Our inability to access capital or significant increases in the cost of capital could adversely affect our financial condition and results of operations.

Our ability to obtain adequate and cost effective short-term and long-term financing depends on maintaining investment grade credit ratings as well as the existence of liquid and stable financial markets. Our businesses rely on access to capital markets, including commercial paper, debt capital markets and equity 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. Disruptions in the capital markets could adversely affect our ability to access short-term and long-term financing. 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. 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 negatively impact our ability to run our business and make strategic investments.

A negative change in our current credit ratings, particularly below investment grade, could adversely affect our cost of borrowing and/or access to sources of liquidity and capital. Such a downgrade could further limit our access to borrowing under available credit lines. Additionally, downgrades in our current credit ratings below investment grade could cause additional delays in accessing the capital markets by the utility while we seek supplemental state regulatory approval, which could hamper our ability to access credit markets on a timely basis. A credit downgrade could also require additional support in the form of letters of credit, cash or other forms of collateral and otherwise adversely affect our financial condition and results of operations.

Changes in accounting standards. Changes in accounting standards may adversely impact our financial condition and results of operations.

The SEC is currently considering whether issuers in the United States should be required to prepare financial statements in accordance with International Financial Reporting Standards (IFRS) instead of the current generally accepted accounting principles (GAAP) in the United States. IFRS is a comprehensive set of accounting standards promulgated by the International Accounting Standards Board (IASB), which are currently in effect for most other countries in the world. The SEC has indicated that it will decide in 2011 whether IFRS will be required for U.S. companies. If the SEC decides to adopt IFRS, we expect that U.S. companies would not be required to report under these new standards until 2015 or 2016 at the earliest. Unlike U.S. GAAP, IFRS does not currently provide an industry accounting standard for rate-regulated activities. As such, if IFRS were adopted in its current state, we may be precluded from applying certain regulatory accounting principles, including the recognition of certain regulatory assets and regulatory liabilities. The potential issues associated with rate-regulated accounting, along with other potential changes associated with the adoption of IFRS, may adversely impact our financial condition and results of operations, should adoption of IFRS be required. Also, the U.S. Financial Accounting Standards Board is considering various changes to U.S. GAAP, some of which may be significant, as part of a joint effort with the IASB to converge accounting standards over the next several years. If approved, adoption of these changes may adversely impact our financial condition and results of operations.

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Risks Related Primarily to Our Local Utility Business

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.

The cost of natural gas is affected by a variety of factors, including weather, changes in demand, the level of production and availability of natural gas, imports of natural gas, transportation constraints, availability of pipeline capacity, transportation capacity cost increases, federal and state energy and environmental regulation and legislation, the degree of market liquidity, supply disruption, natural disasters, wars and other catastrophic events, national and worldwide economic and political conditions, and the price and availability of alternative fuels. In our utility segment, the cost we pay for natural gas at the utility 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 utility customers, thereby potentially causing those customers to conserve or 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 several months or even a year 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 estimated average PGA gas cost in rates and the actual average gas cost incurred be recognized as current income or expense (see Part II, Item 7., “Results of Operations—Regulatory Matters—Rate Mechanisms”). Accordingly, higher average gas costs than those assumed in setting rates can adversely affect our operating cash flows, liquidity and results of operations. 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.

Customer growth risk. Our utility margin, earnings and cash flow may be negatively affected if we are unable to sustain customer growth rates in our local gas distribution segment.

Our utility 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. Continued weakness in the residential new construction and conversion market, and continued decline in average use of natural gas by our residential and commercial customers, could result in an adverse long-term impact on our utility margin, earnings and cash flows.

Risk of competition. Our gas distribution business is 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, propane, and renewable energy providers. We also compete with suppliers of electricity, fuel oil and renewable energy providers for commercial applications. In the industrial market, we compete with suppliers of all forms of energy, including oil, electricity, renewable energy providers and, as it relates to sources of energy for electric power plants, coal and hydro. Competition among these forms of energy is based on price, efficiency, reliability, performance, market conditions and technology.

Higher natural gas prices have at times eroded, or in some cases eliminated, the competitive price advantage of natural gas over other energy sources. Technological improvements in other energy sources could also erode our competitive advantage. If natural gas prices rise relative to other energy sources, it may negatively affect our ability to attract new customers or retain our existing residential, commercial and industrial customers, which could have a negative impact on our customer growth rate and results of operations.

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Reliance on third parties to supply natural gas risk. We rely on third parties to supply substantially all of the natural gas in our distribution segment, and limitations on our ability to obtain supplies could have an adverse impact on our financial results.

Our ability to secure natural gas for current and future sales depends upon our ability to purchase and deliver supplies of natural gas from third parties, 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 drilling of new wells and operating 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 adversely 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, transporting gas into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from the Alberta and the U.S. Rocky Mountain supply basins. If there is a rupture or inadequate capacity in the pipeline, we may not be able to meet our customers' gas requirements and we would likely incur costs associated with actions necessary to mitigate service disruptions, both of which would negatively impact our results of operations

Weather risk. Warmer than average weather or a failure to renew our weather normalization mechanism may have a negative impact on our revenues and results of operations.

We are exposed to weather risk primarily in our utility 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 colder weather typically results in higher gas sales. 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, colder weather could adversely affect utility margin because we may be required to purchase gas at spot rates in a rising price market to secure sufficient volumes to meet customer requirements. Approximately 9 percent of our Oregon residential and commercial customers have opted out of the weather normalization mechanism and 10 percent of our customers are in Washington where we do not have a weather normalization mechanism. Furthermore, continuation of the weather normalization mechanism in Oregon after October 2012 is 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 or a failure to renew our conservation tariff may have a negative impact on our revenues.

An increasing national focus on energy conservation, including improved building practices and appliance efficiencies, may result in increased energy conservation by customers, which can decrease our sales of natural gas and adversely affect our results of operations. In Oregon, we have a conservation tariff which is designed to recover lost margin due to declines in residential and commercial customers' consumption. The conservation tariff is scheduled to expire in October 2012. The failure of the OPUC to extend the conservation tariff in the future could adversely affect our financial condition, results of operations and cash flows. We do not have a conservation tariff in Washington.

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Business improvements risk. Our efforts to integrate, consolidate and streamline our operations have resulted in increased reliance on technology, the failure of which could adversely affect our financial condition and results of operations.

Over the last several years we have undertaken a variety of initiatives to integrate, standardize, centralize and streamline our operations. These efforts have resulted in greater reliance on technological tools such as: an enterprise resource planning system, which provides an integrated suite of business application software; an automated dispatch system, which provides integrated planning, scheduling and dispatching of field resources; an automated meter reading system, which allows for electronic reading of customers meters; and other similar technological tools and initiatives. The failure of any of these or other similarly important technologies, or our inability to have these technologies supported, updated, expanded or integrated into other technologies, could adversely impact our operations. Although we have, when possible, developed alternative sources of technology and built redundancy into our computer networks and tools, there can be no assurance that these efforts to date would protect us against all potential issues or disaster occurrences related to the loss of any such technologies or their use.

Risks Related Primarily to Our Gas Storage Business

Long-term stabilization of gas price risk. Any significant stabilization of natural gas prices could have a negative impact on the demand for our natural gas storage services, which could adversely affect our financial results.

Storage businesses benefit from price volatility, which impacts the level of demand for services and the rates that can be charged for storage services. On a system-wide basis, natural gas is typically injected into storage between April and October when natural gas prices are generally lower and withdrawn during the winter months of November through March when natural gas prices are typically higher. However, the market for natural gas may not continue to experience volatility and seasonal price sensitivity in the future at the levels previously seen. If price volatility and seasonal price sensitivity in the natural gas industry decrease because of increased production capacity or otherwise, then the demand for our storage services and the prices that we will be able to charge for those services may decline. A sustained decline in these prices could have an adverse affect on our financial condition, results of operations and cash flows.

Natural gas storage competition risk. Increasing competition in the natural gas storage business could reduce the demand for our storage services and drive prices down for our storage business, which could adversely affect our financial condition, results of operation and cash flows.

Our natural gas storage segment competes primarily with other storage facilities and pipelines in the storage of natural gas.   Natural gas storage is an increasingly competitive business, with ongoing and proposed third-party construction of new storage capacity and expansions of existing facilities in California, the U.S. Rocky Mountains and elsewhere in the United States and Canada.   Increased competition in the natural gas storage business could reduce the demand for our natural gas storage services, drive prices down for our storage business, and adversely affect our ability to renew or replace existing contracts at rates sufficient to maintain current revenues and cash flows, which could adversely affect our financial condition, results of operations and cash flows.

Third-party pipeline risk. Our gas storage business depends on third-party pipelines that connect to our gas storage facilities, the failure or unavailability of which could adversely affect our financial condition, results of operations and cash flows.

Our gas storage facilities are reliant on the continued operation of a third-party pipeline and other facilities that provide delivery options to and from our storage facilities.   Because we do not own all of these pipelines, their operation is not within our control. If the third-party pipeline to which we are connected were to become unavailable for current or future withdrawals or injections of natural gas due to repairs, damage to the infrastructure, lack of capacity or other reason, our ability to operate efficiently and satisfy our customers' needs could be compromised, thereby potentially reducing our revenues and cash flows.

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Commencement of operations at new storage facility risk. Commencement of operations at our new Gill Ranch storage facility involves numerous operational risks that may result in a failure to meet expectations or contractual obligations, additional or unexpected costs and other business risks that could adversely impact our financial condition, results of operations and cash flows.

In October, 2010 we commenced operations at our Gill Ranch storage facility. Operations at a new storage facility involve many risks. Although we believe that Gill Ranch has been designed to meet our contractual obligations and project specifications with respect to injection, withdrawal and gas specifications, the facility is new and has a limited operating history. If we fail to achieve designed capacity, inject or withdraw natural gas at the levels we expect or at contracted rates, or cannot deliver natural gas consistent with our expectations or contractual specifications, or otherwise operate as expected, or if operating costs are substantially higher than we expect or if we fail to control those costs, we may not be able to contract for storage at the levels and on the terms we expect, and we could incur higher than expected costs to satisfy our contractual obligations under contracts we obtain and this could adversely impact our results of operations or cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments.

ITEM 2. PROPERTIES

Utility Properties

Our natural gas distribution system consists of approximately 13,900 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 expires on May 31, 2018. Resource centers are maintained on owned or leased premises at convenient points in the distribution system to provide service within our utility service territory. We own LNG storage facilities in Portland and near Newport, Oregon.

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.

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Gas Storage Properties

We hold leases and other property interests in approximately 9,900 net acres of underground natural gas storage in Oregon and approximately 5,000 net acres of underground natural gas storage in California, and easements and other property interests related to pipelines associates with those facilities. 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.

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 15 and as discussed below, we have only routine nonmaterial litigation in the ordinary course of business.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon, Case Number 1012-17532. The defendants include Associated Electric & Gas Insurance Services Limited, Allianz Global Risk US Insurance Company, certain underwriters at Lloyd's London, certain London market insurance companies and ten other insurance companies. In the suit, NW Natural alleges that the defendant insurance companies issued third party liability insurance policies to NW Natural and that the defendants have breached the terms of those policies by failing to indemnify NW Natural for liabilities arising from environmental contamination at certain sites caused or alleged to be caused by its historical operations. NW Natural seeks damages in excess of $40 million in losses it has incurred to date, as well as declaratory relief for additional losses it expects to incur in the future.

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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:

	2010		2009	
Quarter Ended	High	Low	High	Low
March 31	$47.54	$41.05	$45.66	$37.71
June 30	49.18	41.90	46.07	39.58
September 30	49.00	42.63	46.00	41.12
December 31	50.86	44.02	46.47	40.83

The closing quotations for our common stock on December 31, 2010 and 2009 were $46.47 and $45.04, respectively.

(B) As of December 31, 2010, there were 7,135 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	2010	2009
February 15	$0.415	$0.395
May 15	0.415	0.395
August 15	0.415	0.395
November 15	0.435	0.415
Total per share	$1.680	$1.600

The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. Subject to Board approval, we expect 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.

(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 2010:

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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
10/01/10 - 10/31/10	1,182	$50.73	-	-
11/01/10 - 11/30/10	22,462	$48.79	-	-
12/01/10 - 12/31/10	1,517	$46.75	-	-
Total	25,161	$48.76	2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2010, 21,642 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, 3,519 shares of our common stock were purchased on the open market during the quarter to meet the requirements of our share-based programs. During the quarter ended December 31, 2010, 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 common stock share repurchase program under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2011 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the quarter ended December 31, 2010, no shares of our common stock were purchased pursuant to this program. Since the program's inception in 2000 we have repurchased approximately 2.1 million shares of common stock at a total cost of approximately $83.3 million.

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ITEM 6. SELECTED FINANCIAL DATA

Thousands, except per share amounts and ratio of earnings to fixed charges	For the year ended December 31, 2010	2009	2008	2007	2006
Utility operating revenues:					
Residential sales	$ 456,174	$ 555,844	$ 566,840	$ 555,312	$ 536,468
Commercial sales	227,994	292,697	298,943	298,800	290,666
Industrial - firm sales	30,830	41,407	46,579	54,567	66,986
Industrial - interruptible sales	36,164	62,116	68,978	74,876	93,107
Total gas sales revenues	751,162	952,064	981,340	983,555	987,227
Transportation	13,833	13,635	14,288	14,191	12,800
Regulatory adjustment for income taxes paid (1)	7,721	5,884	1,760	5,996	-
Other revenues	17,917	21,166	21,784	12,228	161
Total gross utility operating revenues	790,633	992,749	1,019,172	1,015,970	1,000,188
Cost of gas sold	424,494	611,088	656,504	639,094	648,081
Revenue taxes	19,991	24,656	25,072	25,001	24,840
Utility net operating revenues	346,148	357,005	337,596	351,875	327,267
Non-utility net operating revenues	21,433	19,882	18,619	17,167	12,909
Net operating revenues	$ 367,581	$ 376,887	$ 356,215	$ 369,042	$ 340,176
Net income	$ 72,667	$ 75,122	$ 69,525	$ 74,497	$ 63,415
Average common shares outstanding:					
Basic	26,589	26,511	26,438	26,821	27,540
Diluted	26,657	26,576	26,594	26,995	27,657
Earnings per share of common stock:					
Basic	$ 2.73	$ 2.83	$ 2.63	$ 2.78	$ 2.30
Diluted	$ 2.73	$ 2.83	$ 2.61	$ 2.76	$ 2.29
Dividends paid per share of common stock	$ 1.68	$ 1.60	$ 1.52	$ 1.44	$ 1.39
Total assets - at end of period	$ 2,616,616	$ 2,399,252	$ 2,378,152	$ 2,014,061	$ 1,956,856
Long-term debt	$ 591,700	$ 601,700	$ 512,000	$ 512,000	$ 517,000

Ratio of earnings to fixed charges	3.73	3.86	3.76	3.92	3.40

(1) Regulatory adjustment for income taxes paid is the result of the implementation of the utility regulation in 2007 (see Part II, Item 7., "Business Segments - Utility Operations - Regulatory Adjustment for Income Taxes Paid").

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SELECTED FINANCIAL DATA
(continued)

Thousands, except customers and statistics	For the year ended December 31, 2010	2009	2008	2007	2006
Capitalization - at end of period					
Common stock equity	$693,101	$660,105	$628,373	$594,751	$599,545
Long-term debt	591,700	601,700	512,000	512,000	517,000
Total capitalization	$1,284,801	$1,261,805	$1,140,373	$1,106,751	$1,116,545
Gas sales and transportation deliveries (therms):					
Residential	368,682	412,867	428,787	398,960	382,665
Commercial	230,196	255,593	265,531	249,659	242,683
Industrial - firm	37,085	39,447	47,340	52,340	66,971
Industrial - interruptible	58,387	72,525	87,484	89,128	112,736
Total gas sales	694,350	780,432	829,142	790,087	805,055
Transportation	367,619	350,933	431,609	424,882	387,594
Total utility volumes sold and delivered	1,061,969	1,131,365	1,260,751	1,214,969	1,192,649
Customers (average for period):					
Residential	607,645	601,989	594,481	580,346	564,700
Commercial	62,334	62,142	61,756	60,749	59,889
Industrial - firm	590	610	625	634	650
Industrial - interruptible	153	169	180	189	197
Transportation	174	158	136	128	99
Total customers	670,896	665,068	657,178	642,046	625,535
Statistics:					
Heat requirements:					
Actual degree days	4,171	4,383	4,576	4,374	4,089
Percent colder (warmer) than average	(2%)	3%	7%	3%	(4%)
Average annual use per customer in therms:					
Residential	616	686	721	687	678
Commercial	3,699	4,113	4,300	4,110	4,052
Gas purchased cost per therm - net (cents)	61.36	71.96	86.56	75.00	75.37

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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, 2010, 2009, and 2008. 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 direct and indirect wholly-owned subsidiaries which include: Gill Ranch Storage, LLC (Gill Ranch), NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), and NNG Financial Corporation (NNG Financial). These statements also include accounts related to an equity investment in Palomar Gas Holdings, LLC (PGH), which is developing a proposed natural gas pipeline through its wholly-owned subsidiary Palomar Gas Transmission LLC (Palomar). These accounts include our regulated local gas distribution business, our 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 (distribution), and the term "non-utility" is used to describe our gas storage segment (gas storage) as well as our other regulated and non-regulated investments and business activities (other segment). For a further discussion of our business segments, see Note 4.

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 consolidated earnings. All references in this section to earnings per share are on the basis of diluted shares. We also show operating revenues and margins excluding the refund of gas cost savings to customers in June and July 2009 because we believe it provides a more meaningful comparison of operating revenues and margins between 2009 and 2010. We also present free cash flow (see "Cash Flows – Financing Activities," below). We use such non-GAAP (i.e. non-generally accepted accounting principles) measures in analyzing our financial performance and believe that they provide useful information to our investors and creditors in evaluating our financial condition and results of operations.

Executive Summary

Highlights of 2010 include:

- Consolidated earnings of $72.7 million and $2.73 per share in 2010 compared to $75.1 million and $2.83 in 2009;
- Operating revenues (margin) of $367.6 million, a decrease of 2 percent;
- Total operating expenses of $210.0 million, a decrease of 4 percent;
- Interest expense of $42.6 million, minus other income of $7.1 million, for a net decrease of 4 percent;
- Cash flow from operations of $126.5 million, a decrease of $113.9 million;
- Gill Ranch gas storage facility completed and operations started-up in the fourth quarter of 2010;
- Utility customer growth rate of 0.9 percent in 2010, compared to 0.8 percent in 2009;
- A #1 overall ranking for the best gas utility in the nation on the J.D. Power and Associates residential customer satisfaction survey, and a #1 ranking for best in the West on the business customer satisfaction survey; and
- Dividends paid increased 5 percent to $1.68 per share in 2010, making this the 55th consecutive year of increasing dividends paid to shareholders.

Our primary businesses consist of regulated utility and gas storage operations. Factors critical to the success of the utility 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 reasonable and timely manner. Our utility business is regulated by two state commissions, the Public Utility Commission of Oregon (OPUC) and the Washington Utilities and Transportation Commission (WUTC). Factors critical to the success of our gas storage business include: developing and operating storage capacity at competitive market prices; retaining existing customers and successfully marketing available 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; appropriate rates; and with respect to future development of gas storage projects, being able to obtain financing to fund future development. Our gas storage business is, in part, regulated by the California Public Utilities Commission (CPUC).

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2011 Outlook

In 2011, we intend to remain focused on improving our core businesses, enhancing our strategic position, advancing business development projects related to our primary business segments, and strengthening our organizational effectiveness. The following is a brief summary of management's plans and objectives in these four areas. For further information, see "Issues, Challenges and Performance Measures," and "Strategic Opportunities," below.

Business improvements. We continue to develop, integrate, consolidate and streamline operations using recently acquired new technology, which include an enterprise resource planning system, an automated dispatching system and an automated meter reading system. These and other new technologies support our operating model.

Strategic position. We remain committed to creating shareholder value while balancing the interests of our customers, employees and the communities we serve. To create value, we anticipate and respond to business challenges and opportunities that lie ahead, including finding innovative solutions to economic and environmental challenges as well as regulatory, workforce and business development challenges and opportunities, such as the potential investment in long-term gas reserves on behalf of our utility customers.

Business development. We continue to focus on the development of our underground gas storage businesses, the natural gas infrastructure investment in Palomar and key utility initiatives.

Organizational effectiveness. Our employees are our most valued resource. We intend to support our employees with a positive and safe work environment, on-going training opportunities, continued refinement of our organizational structure and new technologies to achieve goals and facilitate improvements.

Issues, Challenges and Performance Measures

Economic weakness. Ongoing weakness in local and U.S. economies has continued to impact utility customer growth, business demand for natural gas and gas storage prices. Most recently, our utility's annual customer growth rate increased slightly to 0.9 percent at December 31, 2010, compared to 0.8 percent in 2009 and 1.6 percent in 2008. We are still faced with 10 to 11 percent unemployment rates in Oregon and southwest Washington and a sluggish business environment. However, despite these challenges we believe we are well positioned to continue adding utility customers due to lower natural gas prices, our relatively low market penetration, our efforts to convert homes to natural gas, and the potential for environmental initiatives that could favor natural gas use in our region.

Managing gas prices and supplies. Our gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices to effectively manage costs, reduce price volatility and maintain a competitive advantage. With recent success in new drilling technologies and substantial new supplies from shale gas formations around the U.S. and in Canada, the supply of North American natural gas has increased dramatically, which has contributed to lower and more stable gas prices. We entered the 2010-11 gas contract year, which began November 1, 2010, hedged on gas commodity prices at approximately 77 percent of our forecasted purchase volumes. In addition, we are currently hedged at approximately 45 percent for the 2011-12 gas contract year and between 5 and 10 percent for the 2012-13 gas contract year. Our Purchased Gas Adjustment (PGA) mechanism, along with our gas price hedging strategies and gas supplies in storage, enable us to reduce earnings risk exposure and secure lower gas costs for customers. These lower gas prices, coupled with good customer service and energy efficiency programs for customers, can help strengthen natural gas' competitive price advantage compared to other fuels. In addition to hedging gas prices over the next few years, we are evaluating and developing other gas acquisition strategies to potentially manage gas price volatility for customers beyond three years, including possible investment in long-term gas reserves. Although stable gas prices provide opportunities to manage costs for our distribution customers, they present challenges for our gas storage business by lowering the value of, and reducing demand for, storage services and limiting Gill Ranch's ability to contract for longer terms at favorable prices.

Environmental costs. We accrue all material environmental loss contingencies related to our properties that require environmental investigation or remediation. Due to numerous uncertainties surrounding the preliminary nature of investigations or the developing nature of remediation requirements, actual costs could vary significantly from our loss estimates. As a regulated utility, we are required to defer certain costs pursuant to regulatory decisions. We currently have a regulatory order to defer certain environmental costs, and to seek recovery of these amounts in future rates to customers. However, before we can seek recovery from customers, we are expected to pursue recovery from insurance policies. Ultimate recovery of environmental costs, either from regulated utility rates or from insurance, will depend on our ability to effectively manage costs and demonstrate that costs were prudently incurred. Recovery may vary significantly from amounts currently recorded as regulatory assets, and amounts not recovered would be required to be charged to income in the period they were deemed to be unrecoverable. See Note 15.

Climate change. We recognize that our businesses will be impacted by future carbon constraints. The outcome of federal, state, local and international 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. For example, in September 2009, the EPA issued a final rule requiring the annual reporting of greenhouse gas emissions from certain industries, specified large greenhouse gas emission sources, and facilities that emit 25,000 metric tons or more of CO_2 equivalents per year. The first reports are due by March 31, 2011 for emissions occurring on or after January 1, 2010. Under this reporting rule, local gas distribution companies are required to report system throughput to the EPA on an annual basis. The EPA also issued additional greenhouse gas reporting regulations in November 2010 requiring the annual reporting of fugitive emissions, an unintended release of gas, from our operations. The first report under these more recent regulations is due by March 31, 2012. Lawsuits have been filed challenging the EPA's regulation of greenhouse gas emissions and members of the U.S. Congress have discussed proposing legislation that would limit the EPA's ability to regulate greenhouse gas emissions. While our CO_2 equivalent emission levels are relatively small, the adoption and implementation of any regulations imposing reporting obligations, or limiting emissions of greenhouse gases associated with our operations, could result in an increase in the prices we charge our customers or a decline in the demand for natural gas. On the other hand, because natural gas has a relatively low carbon content, it is also possible that future carbon constraints could create additional demand for natural gas for electric generation, direct use in homes and businesses and as a reliable and relatively low-emission back-up fuel source for alternative energy sources.

Performance measures. In order to deal with the challenges affecting our businesses, we annually review and update our strategic plan to map our course over the next several years. Our plan includes strategies for: further improving our utility gas distribution business; growing our non-utility gas storage business; investing in new natural gas infrastructure in the region; and maintaining a leadership role within the gas utility industry by addressing long-term energy policies and pursuing business opportunities that support new clean energy technologies. We intend to measure our performance and monitor progress on certain metrics including, but not limited to: earnings per share growth; total shareholder return; return on invested capital; utility return on equity; utility customer satisfaction ratings; utility margin; utility capital and operations and maintenance expense per customer; and non-utility earnings before interest, taxes, depreciation and amortization (non-utility EBITDA).

Strategic Opportunities

Business Process Improvements. To address the current economic and competitive challenges, we continue to evaluate and implement business strategies to improve efficiencies. Our goal is to develop, integrate, consolidate and streamline operations and support our employees with new technology tools.

In 2009, we announced a voluntary severance program to reduce staffing levels in response to work load declines related to the low customer growth environment and efficiency improvements. Severance programs and normal attrition resulted in reductions of full-time positions from 1,133 at December 31, 2008 to slightly over 1,000 in 2010, and the savings are reflected in decreases in utility operation and maintenance costs and utility capital expenditures.

Technology investments, workforce reductions and other initiatives implemented over the last couple years contributed to a 9 percent decrease in utility operation and maintenance cost in 2010, and these efforts are expected to contribute to long-term operational efficiencies and lower operating and capital costs throughout NW Natural.

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Gas Storage Development. We have a joint agreement with Pacific Gas and Electric Company (PG&E) on an underground natural gas storage facility near Fresno, California. Our 75 percent undivided ownership interest in the facility is held by our wholly-owned subsidiary, Gill Ranch. Gill Ranch is also the sole operator of the project. Construction on this facility began in January 2010, with a majority of the construction work completed by October 2010 and the remainder of the construction work expected to be completed in 2011. Our share of the initial development is designed to provide 15 Bcf of gas storage capacity by the end of 2013 and an associated capacity on the approximate 27 miles of gas transmission pipeline. Gill Ranch began operations during the fourth quarter of 2010. See Note 4.

Gill Ranch is offering storage services to the California market at market-based rates, subject to CPUC regulation including, but not limited to, service terms and conditions, tariff regulations, and security issuances. Due to increasing supplies and price stability of natural gas in North America, and declining demand for natural gas due to recent economic conditions, current storage values are expected to remain low in the near term, which will likely affect the prices at which Gill Ranch is able to contract.

The initial construction costs of Gill Ranch included the construction of some infrastructure that will accommodate a potential expansion of the Gill Ranch facility. Subject to market demand, project execution, available financing and receipt of future permits, we have the operational capacity to expand the Gill Ranch facility beyond our and PG&E's combined permitted capacity of 20 Bcf, without further expansion of our takeaway pipeline system. Taking these considerations into account and with certain infrastructure modifications, we currently estimate that the Gill Ranch storage facility could support an aggregate storage capacity of around 40 Bcf, of which we would have the rights to an aggregate of 20 Bcf or 50 percent of total estimated storage capacity.

The Pacific Northwest storage markets also are negatively impacted by lower gas prices and lack of gas price volatility, but less so than in California. In 2011, we expect to continue planning for possible expansion of our gas storage facilities near Mist, Oregon in anticipation of increased natural gas demand for electric generation in the Pacific Northwest. Currently we do not have a set timeline for development, but we believe the earliest timeframe for moving forward with the next Mist expansion is 2013. In the meantime, we will continue to monitor the market demand and work on preliminary design and project scope, which will ultimately require the development of storage wells, potentially a second compression station and additional pipeline gathering facilities that will enable future storage expansions.

Pipeline Diversification. Currently our utility and gas storage at Mist depend on a single bi-directional interstate transmission pipeline to ship gas supplies. Palomar, a wholly-owned subsidiary of PGH, seeks to build a new gas transmission pipeline that would provide an interconnection with our utility distribution system. PGH is owned 50 percent by us and 50 percent by Gas Transmission Northwest Corporation (GTN), an indirect wholly-owned subsidiary of TransCanada Corporation. The proposed Palomar pipeline includes an east and a west segment and is designed to serve our utility and the growing natural gas markets in Oregon and other parts of the Pacific Northwest. The proposed pipeline would be regulated by the FERC.

In May 2010, we learned that the company proposing to build an LNG terminal on the Columbia River had suspended its operations and filed for bankruptcy. This company had previously entered into a binding precedent agreement with Palomar for a majority of the proposed pipeline's capacity. In September 2010, the bankruptcy court rejected and terminated the precedent agreement and ruled in Palomar's favor with regards to a lien on the bankrupt company's assets. Palomar currently has taken title to all of the bankrupt shipper's assets based upon the bankruptcy court's final decision in this matter in October 2010.

Palomar also has a non-binding memorandum of understanding with The Williams Companies' Northwest Pipeline (Northwest Pipeline) that contemplates Northwest Pipeline becoming a part owner in the Palomar project and which consolidates the region's efforts to develop a cross-Cascades pipeline around the use of the Palomar route. Northwest Pipeline owns and operates the single, bi-directional pipeline that connects to NW Natural's utility distribution system. In early February 2011, Palomar held a workshop with the OPUC, WUTC and other Pacific Northwest parties to address the aggregate gas infrastructure needs for the region. Palomar expects to have an open season in 2011 and focus on permitting activities with FERC during 2011. The date for when the Palomar pipeline is expected to go into service will be impacted by the timing of our final FERC permit and the needs of shippers. See "Financial Condition—Cash Flows—Investing Activities," below for further discussion on the status of Palomar.

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As of December 31, 2010, our net equity investment in PGH, which in turn has been invested in Palomar, was $14.8 million. As of December 31, 2010, Palomar had invested a total of $45.6 million of capital costs for the pipeline development, including allowance for funds used during construction (AFUDC). Palomar recovered $15.8 million from a letter of credit which supported the bankrupt shipper's obligations under its prior precedent agreement, and title to certain assets from the bankrupt company's liquidation.

In October 2010, Palomar executed an agreement with the Confederated Tribe of the Warm Springs Reservation that provides Tribal consent for the Bureau of Indian Affairs to issue a pipeline right-of-way grant across the Warm Springs Reservation. Adoption of this route for the east segment will both shorten the pipeline length and reduce its environmental impact relative to the initially proposed route in Palomar's FERC application.

We believe the proposed pipeline's east segment is still a viable project, and the Palomar project remains in a development stage. We performed an impairment analysis for our total equity investment as of December 31, 2010 and determined that no impairment write-down is needed (see Note 12).

Consolidated Earnings and Dividends

Consolidated net income was $72.7 million, or $2.73 per share, for the year ended December 31, 2010, compared to $75.1 million, or $2.83 per share, and $69.5 million, or $2.61 per share, for the years ended December 31, 2009 and 2008, respectively. Consolidated earnings decreased in fiscal year 2010 primarily due to lower earnings from our gas storage segment, which reflects partial year operations and start-up expenses for our subsidiaries Gill Ranch and NWN Gas Storage. These decreases were partially offset by increased earnings reported by our utility gas distribution business and our ongoing interstate gas storage business at Mist. Consolidated returns on average stockholders' equity for these three years were 10.7 percent, 11.7 percent and 11.4 percent, respectively.

2010 compared to 2009:

The most significant factors contributing to the $2.4 million decrease in consolidated net income were:

- a $13.5 million decrease in utility net operating revenue (margin) from the regulatory gas cost incentive sharing mechanism, which reflects gains of $15.1 million in 2009 compared to gains of $1.6 million in 2010;
- a $2.9 million net loss from Gill Ranch, and a $0.6 million net loss from NWN Gas Storage, primarily reflecting higher operating expenses related to start-up activities;
- a $2.8 million increase in income tax expense primarily reflecting higher taxable income from the utility, including an accelerated amortization of regulatory tax balances related to pre-1981 assets which are offset by increased revenues collected in utility margin; and
- a $1.9 million increase in interest expense primarily reflecting the full year effect of long-term debt issued during 2009 and higher balances of short-term debt outstanding.

Partially offsetting the above factors were:

- a $5.0 million increase in utility margin from residential and commercial customers, after adjustments for weather and decoupling mechanisms, primarily due to colder weather benefits in the second quarter of 2010 when weather normalization was not in effect, customer growth and the rate recovery of higher income tax expenses related to an increase in Oregon tax rates and the accelerated amortization of regulatory tax assets;
- a $14.3 million decrease in utility operating expenses primarily due to lower property tax, payroll, bad debt, and employee benefit costs; and
-

a $3.4 million increase in other income primarily due to higher interest income from utility deferred regulatory account balances and interest income from a utility property tax refund, partially offset by a decrease in the non-utility gains from company-owned life insurance.

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2009 compared to 2008:

Factors contributing to increased earnings were:

- a $20.6 million increase in utility margin from our regulatory share of gas cost savings, reflecting a contribution to margin of $15.1 million in 2009 compared to a reduction to margin of $5.5 million in 2008;
- a $4.1 million increase in utility margin from the regulatory adjustment for income taxes paid; and
- a $1.3 million increase in gas storage margin from higher optimization revenues.

Partially offsetting the above factors were:

- a $13.7 million increase in operations and maintenance expense primarily due to higher utility expenses for pensions, bonuses, health care benefits and employee severance;
- a $6.0 million increase in income tax expense related to higher taxable income and a higher state income tax rate; and
- a $2.1 million decrease in utility margin from industrial customers, reflecting weak economic conditions and a decrease in depreciation rates.

Dividends paid on our common stock were $1.68 per share in 2010, compared to $1.60 per share in 2009 and $1.52 per share in 2008. The Board of Directors declared a quarterly dividend on our common stock of 43.5 cents per share, payable on February 15, 2011, increasing the indicated annual dividend rate to $1.74 per share.

Application of Critical Accounting Policies and Estimates

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

- regulatory cost recovery and amortizations;
- revenue recognition;
- derivative instruments and hedging activities;
- pensions and postretirement benefits;
- income taxes; and
- environmental contingencies.

Management has discussed its current 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 2.

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, authoritative guidance for regulated operations (regulatory accounting) 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. Regulatory accounting 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.

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The conditions we must satisfy to adopt the accounting policies and practices of regulatory accounting, 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.

Because we meet all three conditions, we continue to apply regulatory accounting principles for our utility operations. Future accounting changes, regulatory changes or changes in the competitive environment could require us to discontinue the application of regulatory accounting 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 accounting, regulatory and competitive conditions, we believe that it is reasonable to expect continued application of regulatory accounting for our regulated activities, and that all of our regulatory assets and liabilities at December 31, 2010 and 2009 are recoverable or refundable through future customer rates. The net balance on regulatory asset and liability accounts as of December 31, 2010 and 2009 was $125.8 million and $51.2 million, respectively. See "Industry Regulation" in Note 2.

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, 2010 and 2009 were $64.8 million and $71.2 million, respectively. The decrease in accrued unbilled revenues at year-end 2010 was primarily due to lower volumes in 2010 reflecting warmer weather in late December 2010 and lower customer rates. If the estimated percentage of unbilled volume at December 31, 2010 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 $2.4 million, $0.6 million and $0.3 million, respectively.

Utility revenues also include the recognition of a regulatory adjustment for income taxes paid. This revenue reflects an OPUC rule whereby we are required to automatically 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 further discussion, 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 service to customers. Revenues from our asset optimization partner are recognized as earned based on multiple revenue elements, which is generally over the period of each optimization deal except for a contract with a guaranteed amount which is amortized over the life of the contract.

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Accounting for Derivative Instruments and Hedging Activities

Our gas acquisition and hedging 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 derivative instrument fair value is recorded together with an offsetting entry to a regulatory asset or liability account pursuant to regulatory accounting (see Note 2, “Industry Regulation”), and no unrealized gain or loss is recognized in current income. The gain or loss from the fair value of a derivative instrument subject to regulatory deferral is included in the recovery from, or refund to, utility customers in future periods (see “Regulatory Accounting,” above). If a derivative contract is not subject to regulatory deferral, then the accounting treatment for unrealized gains and losses is recorded in accordance with accounting standards for derivatives and hedging (see Note 2, “Derivatives” and “Industry Regulation”) which is either in current income or in accumulated other comprehensive income under common stock equity on the balance sheet. Our derivative contracts outstanding at December 31, 2010 were measured at fair value using models or other market accepted valuation methodologies derived from observable market data. Our 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, 2010 and 2009, see Note 13.

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 accumulated other comprehensive income for contracts qualifying for hedge accounting.

Derivative contracts not qualifying for regulatory deferral are subject to a hedge effectiveness test to determine the financial statement treatment of each specific derivative. As of December 31, 2010, 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 accounting standards for derivatives and hedging to determine the hedge effectiveness for our interest rate swaps and the dollar offset method for other derivative contracts under accounting standards for derivatives and hedging. 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, interest rate and currency hedge transactions for the last three years:

Thousands		2010		2009		2008
Net gain (loss) on commodity-price swaps - utility	$	(60,362)	$	(172,089)	$	34,256
Net gain (loss) on commodity-price options - utility		(610)		(5,809)		1,527
Net gain (loss) on interest rate swap - utility		-		(10,096)		-
Subtotal on commodity - utility		(60,972)		(187,994)		35,783
Net gain (loss) on foreign currency forward purchases - utility		72		88		(728)
Total realized net gain (loss)	$	(60,900)	$	(187,906)	$	35,055

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 hedges and interest rate hedges, which reflect quarterly mark-to-market valuations, are generally not recognized in current income or accumulated other comprehensive income, but are recorded as regulatory liabilities or regulatory assets, and are offset by a corresponding balance in derivative instruments (see Note 13).

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Accounting for Pensions and Postretirement Benefits

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 postretirement employee benefit plans. We also have a qualified defined contribution plan (Retirement K Savings Plan) for all eligible employees. Only the two qualified defined benefit pension plans and Retirement K Savings Plan have plan assets, which are held in a qualified trust to fund retirement benefits. Effective January 1, 2007 and 2010, the qualified defined benefit retirement plans and postretirement benefits for non-union employees and for union employees, respectively, were closed to new participants. These plans were not available to employees at our NWN Gas Storage affiliate. Instead, non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and our NWN Gas Storage employees, are provided an enhanced Retirement K Savings Plan benefit. Also, effective January 1, 2007 the postretirement Welfare Benefit Plan for Non-Bargaining Unit Employees was closed to new participants after December 31, 2006.

Net periodic pension and postretirement benefit costs (retirement benefit costs) and projected benefit obligations (benefit obligations) are determined in accordance with accounting standards for compensation and retirement benefits using a number of key assumptions including discount rates, rate of compensation increases, retirement ages, mortality rates and an expected long-term return on plan assets (see Note 9). These key assumptions have a significant impact on the pension amounts recorded and disclosed. Retirement benefit 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, if applicable. The market-related asset valuation reflects differences between expected returns and actual investment returns, which we recognize over a three-year period or less from the year in which they occur, thereby reducing year-to-year volatility in retirement benefit costs.

Accounting standards also require balance sheet recognition of the overfunded or underfunded status of pension and postretirement benefit 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 retirement benefit costs relating to our qualified defined benefit pension and postretirement benefit plans are generally recovered in utility rates which are set based on accounting standards for pensions and postretirement benefits, and as such we received approval from the OPUC pursuant to regulatory accounting to recognize the overfunded or underfunded status as a regulatory asset or regulatory liability based on expected rate recovery, rather than including it as AOCI under common equity (see “Regulatory Accounting”, above, and Note 2, “Industry Regulation”). Also effective January 1, 2011 the OPUC has authorized the use of a pension balancing account to allow differences between the annual pension cost allocated to operation and maintenance expense and the amount recovered annually in rates per the 2003 general rate case to be recorded in a regulatory asset account. The regulatory asset account will earn a carrying cost at the authorized cost of capital rate set by the OPUC.

A number of factors are considered in developing pension and postretirement assumptions, including evaluations of relevant discount rates, an evaluation of expected long-term investment returns based on asset classes and target asset allocations, 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, 2010 measurement date, we reviewed and updated:

- our pension and postretirement weighted-average discount rate assumptions from 6.01 percent to 5.49 percent and from 5.78 percent to 5.16 percent, respectively. 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 annual rate of future compensation increases remained unchanged at a range of 3.25 to 5.0 percent;
- our expected long-term return on qualified defined benefit plan assets remained unchanged at 8.25 percent; and
- other key assumptions as needed based on actual experience and actuarial recommendations.

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At December 31, 2010, our net pension liability (benefit obligations less market value of plan assets) for the two qualified defined benefit plans increased $11.5 million compared to 2009. The increase in our net pension liability is primarily due to the $29.3 million increase in our pension obligation, which was partially offset by our $10 million cash contribution. The liability for non-qualified plans increased $2.1 million and the liability for other postretirement benefits increased $2.9 million in 2010.

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 return, 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, 2010, 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 13.2 percent, 3.4 percent, 4.5 percent and 10.3 percent, respectively.

We believe our assumptions to be appropriate based on plan design and an assessment of market conditions. However, if our pension assumptions changed 0.25 percent, the retirement benefits costs would change by $1.5 million and the benefit obligations would change by $10.3 million. If our other post retirement obligations assumptions changed by 1 percent, then our health care benefit cost would change by less than $0.1 million and the benefit obligation would change by $0.7 million.

Accounting for Income Taxes

We account for income taxes in accordance with accounting standards that require the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between financial statement carrying amount and tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. At December 31, 2010 and 2009, our net long-term deferred tax liability totaled $373.4 million and $300.9 million, respectively. 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 local income 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, 2010, we did not have a valuation allowance due to our expectation that all of these assets will be realized.

These accounting standards also require the recognition of 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, 2010 and 2009, we had regulatory assets representing differences between book and tax basis related to pre-1981 property of $72.3 million and $76.2 million, respectively, and recorded an offsetting deferred tax liability. We received authorization from the OPUC and WUTC in 2009 to accelerate the recovery of these pre-1981 regulatory assets through future utility rates. See Notes 2 and 10.

Uncertain tax positions are accounted for in accordance with accounting standards that require management’s assessment of the expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are sustained by the taxing authorities, we would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company’s consolidated balance sheet. As of December 31, 2010, we had no uncertain tax positions.

The Internal Revenue Service (IRS) is currently examining our 2006 through 2008 consolidated federal income tax returns. The IRS completed its last examination of the 2002 through 2004 audit cycle in the second quarter of 2006. Completion of the 2006 through 2008 federal income tax return examination is expected during the first quarter of 2011. Currently we do not have any uncertain tax positions that will have a material impact on our results of operations.

The Oregon Department of Revenue (ODOR) is also examining our 2006 through 2008 consolidated income tax returns. Completion of this examination is expected during the first quarter of 2011. Interest and penalties, if any, related to income tax adjustments for prior years will be recorded within income tax expense in the consolidated statements of income.

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 accounting standards for contingencies. Estimates of loss contingencies, including estimates of legal 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 numerous sources, including completed studies and site specific negotiations. 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 $61.0 million as of December 31, 2010. 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, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases we have disclosed the nature of the potential loss and the fact that the high end of the range cannot be reasonably estimated.

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 15.

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, the WUTC, FERC, and with respect to Gill Ranch, the CPUC. The OPUC and WUTC and, with respect to Gill Ranch, the CPUC, also regulate our issuance of securities. In 2010, 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.

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General Rate Cases

Oregon. In our most recent general rate case in Oregon, which was effective in September 2003, the OPUC authorized rates to customers based on a return on common stock 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 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 our most recent general rate case in Washington, the WUTC authorized rates to customers based on a ROE of 10.1 percent, which is included as part of an overall rate of return on total invested capital of 8.4 percent. These customer rates went into effect on January 1, 2009, with annual revenue requirements increased by $2.7 million, or 3 percent.

Federal. We are required under our Mist interstate storage certificate authority and rate approval orders to file every five 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. Our most recent filing of a cost and revenue study was 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, with maximum rates unchanged from prior levels approved by FERC in 2005. In addition, we made a filing 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. These new depreciation rates were designed to match the depreciation rates for the same type of assets approved under state regulation. We did not make any changes to the previously approved maximum rates, and FERC approved the depreciation rate filing in May 2009. We are required to make our next cost and revenue study filing at FERC on or before December 11, 2013.

California. Gill Ranch is authorized by the CPUC to charge market-based rates for the intrastate storage services offered to customers in California.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are established for the utility each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including contract gas purchase prices, gas prices hedged with financial derivatives, gas inventory prices, interstate pipeline demand costs, 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 2010, the OPUC and WUTC approved PGA rate changes effective on November 1, 2010. The effect of these rate changes was to decrease the average monthly bills of Oregon and Washington residential customers by 2 percent. This is our second consecutive year of rate decreases. The OPUC and WUTC also approved rate decreases effective November 1, 2009 of 16 percent and 22 percent in Oregon and Washington, respectively.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select by August 1 of each year either an 80 percent deferral or a 90 percent deferral of higher or lower actual gas costs compared to estimated PGA prices such that the impact on current earnings from the incentive sharing is either

20 percent or 10 percent of the difference between actual and estimated gas costs, respectively. In addition to the gas cost incentive sharing mechanism, we are subject to an annual earnings review to determine if the utility is earning above its allowed ROE threshold. If utility earnings exceed a specific ROE level, then 33 percent of the amount above that level will be deferred for refund to customers. Under this provision, if we select the 80 percent deferral option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90 percent deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. We selected the 90 percent deferral option for both the 2009-2010 and the 2010-2011 PGA years. The ROE threshold is subject to adjustment up or down annually based on movements in long-term interest rates. In September 2010, we received the final report from the OPUC on our 2009 earnings review, which indicated a utility regulated ROE of 11.2 percent. This is below the allowed ROE threshold of 11.5 percent, and therefore no earnings were deferred for refund to customers. Based upon utility results through December 31, 2010, we expect to refund approximately $0.5 million to customers.

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There has been no change to the Washington PGA mechanism under which we defer 100 percent of the higher or lower actual gas costs and pass that difference through to customers as an adjustment to future rates. We do not have an earnings or gas cost sharing mechanism in Washington.

Conservation Tariff. In October 2002, the OPUC authorized the implementation of a “conservation tariff” to adjust utility margin for changes in consumption patterns due to residential and commercial customers’ conservation efforts. The conservation 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’ efforts to conserve energy. In Washington, customer use is not covered by a conservation or decoupling 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 volumes and revenues.

The Oregon conservation tariff includes two components: (1) an annual price elasticity adjustment, which adjusts rates for increases or decreases from expected customer volumes due to changes in commodity costs or changes in our general rates; and (2) a monthly conservation adjustment, which adjusts margin revenues to account for the difference between actual and expected customer 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 “Business Segments - Utility 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 tariff was approved by the OPUC and extended through October 2012.

Weather Normalization. In Oregon, we have an OPUC approved weather normalization mechanism. 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 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 “Business Segments - Utility Operations,” below). The weather normalization mechanism for Oregon utility operations is approved through October 2012. Customers in Oregon are allowed to opt out of the weather normalization mechanism, and as of December 31, 2010, 9 percent had elected to opt out. We do not have a weather normalization mechanism approved for our Washington customers, which account for about 10 percent of our utility volumes and revenues.

Industrial Tariffs. The OPUC and WUTC have approved tariffs covering utility service to our major industrial customers, including terms which are intended to give us certainty in the level of gas supplies we need to acquire to serve this customer group. The terms include an annual election period, special pricing provisions for out-of-cycle changes and a requirement that industrial customers under our annual PGA tariff complete the term of their service election.

System Integrity Program. In 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 (PHMSA). We record these costs as either capital expenditures or regulatory assets, accumulate the costs over each 12-month period, and recover the revenue requirement associated with the costs, subject to audit, through rate changes effective with the annual PGA in Oregon. Congress passed the Pipeline Inspection, Protection, Enforcement, and Safety Act in 2006 which included a legislative mandate for PHMSA to prescribe minimum standards for integrity management programs for natural gas distribution pipelines. The PHMSA issued a proposed rule for distribution integrity management programs in June 2008.

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In February 2009, the OPUC approved a stipulated agreement to create a new, consolidated system integrity program (SIP). The SIP integrates the company's bare steel replacement, transmission pipeline integrity management and distribution pipeline integrity management programs into a single program. In December 2009, the PHMSA issued the final rule for distribution integrity management programs. Our SIP costs are tracked into rates annually, with rate recovery after the first $3.3 million of capital costs. An annual cap for expenditures has been set at $12 million, but extraordinary costs above the cap may be approved with written consent of the OPUC staff and other interested parties and approval of the OPUC. The SIP allows recovery of costs incurred in Oregon during the period from October 2008 through October 2011, or until the effective date of new rates adopted in our next general rate case. The company has initiated discussions with the OPUC and other interested parties to extend the term of the SIP. We do not have any special accounting or rate treatment for SIP costs incurred in the state of Washington.

In 2011 Congress is expected to pass legislation continuing PHMSA's authority to oversee the nation's hazardous liquid and natural gas pipeline infrastructure. The pipeline safety legislation will likely include mandates for additional pipeline safety requirements; however, it is not possible to determine the materiality of possible new pipeline safety regulations at this time.

Regulatory Recovery for Environmental Costs. The OPUC has authorized us to defer environmental costs associated with certain named sites and to accrue interest on 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. These authorizations have been extended through January 2010. We have filed a request for an extension of this deferral and expect to receive this authorization during the first quarter of 2011. See Note 15. In February 2011, we filed a request with the WUTC to defer environmental costs associated with services provided to Washington customers.

Pension Deferral. In March 2010, we filed a request with the OPUC for authorization to defer pension expenses above the amount set in rates, and to recover the amount through a balancing account that would include the effects of anticipated higher and lower pension expenses in future years. The OPUC approved the pension cost balancing account effective January 1, 2011, with accrued interest on the account balance at the utility's authorized rate of return. The estimated reduction to operation and maintenance expense for 2011 is approximately $4 to $5 million. Future year deferrals will depend on changes in plan assets and projected benefit liabilities using a number of key assumptions, as well as our pension contributions. See "Application of Critical Accounting Policies and Estimates," above.

Customer Refunds for Gas Storage Sharing. In June 2010, $11 million was credited to utility customers from our regulatory incentive sharing mechanism related to gas storage and optimization services of pipeline capacity and gas storage at Mist (see "Gas Storage," below). In June 2009, we credited $7.2 million to customers under the same regulatory mechanism.

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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 in Oregon 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.

2010 compared to 2009:

Our utility segment in 2010 earned $66.3 million, or $2.49 per share, compared to $66.0 million, or $2.48 per share in 2009. The major factors contributing to the change were reduced operating expenses largely offset by lower utility margins, which consisted of a $13.5 million decrease from the prior year's gas cost incentive sharing, partially offset by a net $5 million increase in margin from residential and commercial customers, including the effects of the weather normalization and decoupling mechanisms and a $0.7 million increase in industrial margin. Total utility volumes sold and delivered in 2010 decreased by 6 percent over last year due to the effects of warmer weather on residential and commercial use and the lingering effects of a weak economy on commercial use. The regulatory adjustment for income taxes paid also increased margin by $1.8 million compared to 2009.

Our weather normalization mechanism adjusted residential and commercial margins up by $14.0 million for the year ended December 31, 2010 based on weather that was 2 percent warmer than average, compared to a margin reduction of $15.2 million for the year ended December 31, 2009 when weather was 3 percent colder than average. Our decoupling mechanism adjusted residential and commercial margins up by $15.5 million in 2010, after adjusting for expected price elasticity impacts from lower PGA prices effective November 1, 2009, compared to margin adjustments totaling $11.6 million in 2009.

2009 compared to 2008:

Our utility segment in 2009 earned $66.0 million, or $2.48 per share, compared to $58.7 million, or $2.21 per share in 2008. The major factor contributing to the increase in utility margin was a $20.6 million increase in our gas cost incentive sharing from lower gas prices. Total utility volumes sold and delivered in 2009 decreased by 10 percent compared to 2008 due to the effects of warmer weather on residential and commercial use and the effects of a weak economy on commercial and industrial use. Margin was reduced by $11.4 million in 2009 compared to 2008 due to a customer rate decrease which corresponded to a decrease in depreciation rates and expense effective January 1, 2009. Excluding the impact of lower depreciation rates on revenues, our margin from residential and commercial customers increased by $5.2 million in 2009, including the effects of the weather normalization and decoupling mechanisms. Industrial margin declined $2.1 million, but would have decreased by $1.3 million if the depreciation rate impact was excluded. The regulatory adjustment for income taxes paid also increased margin by $4.1 million in 2009 compared to 2008, primarily due to the cost of gas savings in 2009.

Our weather normalization mechanism adjusted residential and commercial margins down by $15.2 million for the year ended December 31, 2009 based on weather that was 3 percent colder than average, compared to a reduction of $15.3 million for the year ended December 31, 2008 when weather was 7 percent colder than average. Our decoupling mechanism increased residential and commercial margin by $11.6 million in 2009, after adjusting for expected price elasticity impacts from higher PGA prices effective November 1, 2008, compared to a margin increase of $4.9 million in 2008.

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The following table summarizes the composition of gas utility volumes and revenues for the years ended December 31, 2010, 2009 and 2008:

Thousands, except degree day and customer data	2010	2009	2008	Favorable/(Unfavorable) 2010 vs. 2009	Favorable/(Unfavorable) 2009 vs. 2008
Utility volumes - therms:					
Residential sales	368,682	412,867	428,787	(44,185)	(15,920)
Commercial sales	230,196	255,593	265,531	(25,397)	(9,938)
Industrial - firm sales	37,085	39,447	47,340	(2,362)	(7,893)
Industrial - firm transportation	127,796	124,218	184,832	3,578	(60,614)
Industrial - interruptible sales	58,387	72,525	87,484	(14,138)	(14,959)
Industrial - interruptible transportation	239,823	226,715	246,777	13,108	(20,062)
Total utility volumes sold and delivered	1,061,969	1,131,365	1,260,751	(69,396)	(129,386)
Utility operating revenues - dollars:					
Residential sales	$ 456,174	$ 555,844	$ 566,840	$ (99,670)	$ (10,996)
Commercial sales	227,994	292,697	298,943	(64,703)	(6,246)
Industrial - firm sales	30,830	41,407	46,579	(10,577)	(5,172)
Industrial - firm transportation	5,702	5,671	6,370	31	(699)
Industrial - interruptible sales	36,164	62,116	68,978	(25,952)	(6,862)
Industrial - interruptible transportation	8,131	7,964	7,918	167	46
Regulatory adjustment for income taxes paid(1)	7,721	5,884	1,760	1,837	4,124
Other revenues	17,917	21,166	21,784	(3,249)	(618)
Total utility operating revenues	790,633	992,749	1,019,172	(202,116)	(26,423)
Cost of gas sold	424,494	611,088	656,504	186,594	45,416
Revenue taxes	19,991	24,656	25,072	4,665	416
Utility margin	$ 346,148	$ 357,005	$ 337,596	$ (10,857)	$ 19,409
Utility margin:(2)					
Residential sales	$ 197,045	$ 217,124	$ 224,683	$ (20,079)	$ (7,559)
Commercial sales	77,831	85,850	90,402	(8,019)	(4,552)
Industrial - sales and transportation	28,451	27,713	29,771	738	(2,058)
Miscellaneous revenues	4,658	6,670	6,381	(2,012)	289
Gain (loss) from gas cost incentive sharing	1,594	15,064	(5,505)	(13,470)	20,569
Other margin adjustments	(647)	2,308	436	(2,955)	1,872
Margin before regulatory adjustments	308,932	354,729	346,168	(45,797)	8,561
Weather normalization adjustment	13,996	(15,236)	(15,266)	29,232	30

Decoupling adjustment	15,499	11,628	4,934	3,871	6,694
Regulatory adjustment for income taxes paid(1)	7,721	5,884	1,760	1,837	4,124
Utility margin	$ 346,148	$ 357,005	$ 337,596	$ (10,857)	$ 19,409
Customers - end of period:					
Residential customers	610,598	604,692	599,285	5,906	5,407
Commercial customers	62,489	62,169	62,115	320	54
Industrial customers	910	933	941	(23)	(8)
Total number of customers - end of period	673,997	667,794	662,341	6,203	5,453
Actual degree days	4,171	4,383	4,576		
Percent colder (warmer) than average weather(3)	(2) %	3 %	7 %		

(1) Regulatory adjustment for income taxes paid is described below.

(2) Amounts reported as margin for each category of customers are net of cost of gas sold and revenue taxes.

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

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In June 2009, we refunded gas cost savings totaling $35.8 million to our Oregon and Washington customers. The following non-GAAP table summarizes the impact of this refund on our operating revenues, cost of gas sold and margin for the year ended December 31, 2009, along with a comparison to the years ended December 31, 2010 and 2008. We believe this non-GAAP financial calculation enables the reader of the financial statements to better understand our operating revenues, cost of gas sold and utility margin performance from management's perspective in addition to the traditional GAAP presentation.

		2009			
Thousands	2010	As Reported	Refund	Excluding Refund (Non-GAAP)	2008
Utility operating revenues:					
Residential sales	$456,174	$555,844	$19,952	$ 575,796	$566,840
Commercial sales	227,994	292,697	11,579	304,276	298,943
Industrial - firm sales	30,830	41,407	1,585	42,992	46,579
Industrial - firm transportation	5,702	5,671	-	5,671	6,370
Industrial - interruptible sales	36,164	62,116	2,673	64,789	68,978
Industrial - interruptible transportation	8,131	7,964	-	7,964	7,918
Regulatory adjustment for income taxes paid	7,721	5,884	-	5,884	1,760
Other revenues	17,917	21,166	-	21,166	21,784
Total utility operating revenues	790,633	992,749	35,789	1,028,538	1,019,172
Cost of gas sold	424,494	611,088	34,691	645,779	656,504
Revenue taxes	19,991	24,656	898	25,554	25,072
Utility margin	$346,148	$357,005	$200	$ 357,205	$337,596

The non-GAAP information disclosed above reconciles to the preceding table summarizing utility margin for the years ended December 31, 2010, 2009 and 2008.

Residential and Commercial Sales

The primary factors that impact results of operations in the residential and commercial markets are 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. For more information on our weather mechanism, see "Regulatory Matters—Rate Mechanisms—Weather Normalization," above.

The primary changes that impacted margin from residential and commercial sales were as follows:

2010 compared to 2009:

- gas sales volumes were 10 percent lower, primarily reflecting 5 percent warmer weather, conservation efforts and weak economic conditions;
- utility operating revenues decreased $164.4 million or 19 percent primarily due to the 10 percent volume decline and customer rate decreases of 16 and 22 percent in Oregon and Washington, respectively, effective November 1, 2009; and
-

utility margin increased $5 million or 2 percent primarily due to customer growth of 0.9 percent and colder weather in the spring of 2010 that was not offset by the Oregon weather normalization mechanism.

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2009 compared to 2008:

- volumes were 4 percent lower, primarily reflecting 4 percent warmer weather, conservation efforts and weak economic conditions;
- utility operating revenues decreased $17.2 million or 2 percent primarily due to $31.5 million in customer refunds for gas cost savings, partially offset by customer rate increases of 14 and 21 percent in Oregon and Washington, respectively, effective November 1, 2008, and customer growth of 0.8 percent; and
- utility margin decreased $5.4 million or 4 percent primarily due to lower volumes and customer rate decreases related to new depreciation rates.

Industrial Sales and Transportation

Industrial sales and transportation revenues include the commodity cost component of gas sold under sales service but not under transportation service. Therefore, industrial customers switching between sales service and transportation service can cause swings in operating revenues but generally our margins are unaffected because our rates do not mark up the cost of gas. As such, we believe margin is a better measure of performance for the industrial sector. The primary changes that impacted margin from industrial sales and transportation were as follows:

2010 compared to 2009:

- volumes delivered to industrial customers increased 0.2 million therms; and
- margin increased $0.7 million, or 3 percent.

2009 compared to 2008:

- volumes delivered to industrial customers decreased 104 million therms, or 18 percent, reflecting reduced usage due to weak economic conditions; and
- margin decreased $2.1 million, or 7 percent, reflecting lower volumes and customer rate decreases related to new depreciation rates, but that was partially offset by fixed charges not affected by declining use.

Several industrial customers transferred from sales service to transportation service in 2010 and 2009. Changes in natural gas prices can result in industrial customers switching between sales and transportation service. In such cases, our tariff allows us to charge the incremental cost of gas supply incurred, if any, to serve those customers so that the cost does not adversely impact our margins or the prices our residential and commercial customers pay.

Regulatory Adjustment for Income Taxes Paid

Oregon law requires regulated natural gas and electric utilities to annually review the amount of income taxes collected in rates from utility operation and compare it to the amount the utility actually pays to taxing authorities. Under this law, if we pay less in income taxes related to utility operations than we collect from Oregon utility customers, or if our utility taxes paid are less than the taxes we collect from Oregon utility customers, then we are required to refund the excess to our Oregon utility customers. Conversely, if we pay more income taxes than we actually collect from Oregon utility customers, then we are required to collect a surcharge from Oregon utility customers.

For the 2008 and 2009 tax years, the OPUC approved our tax filings to recover $0.2 million and $5.1 million, respectively, through a surcharge to Oregon utility customers. It was agreed that the 2008 surcharge, plus accrued interest, would be collected over a one-year period beginning June 1, 2010. It was also agreed that the 2009 surcharge, plus accrued interest, would be collected over a one-year period beginning June 1, 2011. For the 2010 tax year, we estimated the difference between income taxes paid and the amounts collected in rates will result in a surcharge of $7.1 million (excluding interest). The 2009 surcharge was primarily driven by gains from gas cost savings related to our PGA incentive sharing mechanism. The 2010 surcharge was primarily driven by gas cost savings related to our PGA incentive sharing as well as lower utility operating expenses and higher residential, commercial and industrial margins.

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Other Revenues

Other revenues include miscellaneous fee income as well as revenue adjustments reflecting deferrals to, or amortizations from, regulatory asset or liability accounts, except for gas cost deferrals which flow through cost of gas sold. Other revenues increased net operating revenues by $17.9 million in 2010, compared to $21.1 million in 2009 and $21.8 million in 2008.

2010 compared to 2009:

Other revenues decreased $3.2 to $17.9 in 2010 primarily reflecting an increase in decoupling amortization totaling $7.9 million, partially offset by a $4.0 million increase in the refund to utility customers related to the gas storage regulatory sharing mechanism.

2009 compared to 2008:

Other revenues in 2009 were $0.7 million lower than in 2008 primarily reflecting a $6.3 million decrease in the regulatory surcharge for income taxes paid and a $0.7 million decrease in curtailment charges, partially offset by a $7.4 million refund to utility customers related to the gas storage regulatory sharing mechanism.

Cost of Gas Sold

The cost of gas sold includes gas purchases, gas drawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, 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, which occur primarily because of market fluctuations and volatility affecting unhedged gas purchases (see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above). We use natural gas derivatives, primarily fixed-price commodity swaps, consistent with 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 allocated to Washington gas sales, are passed through in customer rates (see "Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities," and "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above, and Note 15). The following summarizes the major factors that contributed to changes in cost of gas sold:

2010 compared to 2009:

- total cost of gas sold decreased $186.6 million, or 31 percent, due to an 6 percent decrease in total sales volumes and a 22 percent decrease in the average cost of gas sold per therm;
- the average gas cost collected through rates decreased from 78 cents per therm in 2009 to 61 cents per therm in 2010, primarily reflecting lower gas prices that were passed on through PGA rate decreases effective November 1, 2009 and 2010; and
- hedge losses totaling $61.0 million were realized and included in cost of gas sold for the year ended December 31, 2010, compared to $187.9 million of hedge losses in the same period of 2009.

2009 compared to 2008:

- total cost of gas sold decreased $45.4 million, or 7 percent, primarily due to a 10 percent decrease in total sales volumes and $34.7 million for gas cost savings refunded to customers;
- the average gas cost collected through rates decreased 1 percent from 79 cents per therm in 2008 to 78 cents per
- therm in 2009, primarily reflecting the reduction to cost of gas sold from customer refunds in 2009, partially offset by our 14 to 21 percent PGA rate increases effective November 1, 2008; and
- net losses totaling $187.9 million were realized from our financial hedges and included in cost of gas sold, compared to $35.1 million of net hedge gains in 2008.

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In 2010, actual gas costs were slightly below those embedded in rates, while in 2009 they were significantly lower and in 2008 they were higher. The effect on shareholders from the gas cost incentive sharing mechanism was a contribution to margin of $1.6 million in 2010 and $15.1 million in 2009 compared to a margin loss of $5.5 million in 2008. For a discussion of our gas cost incentive sharing mechanism, see “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment,” above.

Gas Storage

Our gas storage segment currently consists of the non-utility portion of our Mist underground storage facility, non-utility asset optimization and start-up costs at Gill Ranch. For the year ended December 31, 2010, we earned $6.1 million, or 23 cents per share, from our gas storage segment compared to $8.9 million, or 34 cents per share, for the same period in 2009. This decrease is primarily due to start-up costs at Gill Ranch.

We provide gas storage services to customers in the interstate and intrastate markets from our Mist gas storage field in Oregon, primarily using storage capacity that has been developed in advance of core utility customers' requirements. Under a regulatory incentive sharing mechanism in Oregon, we retain 80 percent of pre-tax income from our Mist gas storage services and from optimization services when the costs of the capacity being used are not included in utility rates, and 33 percent of pre-tax income from such storage and optimization services when the capacity being used is pipeline or is included in utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for credit 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 have a joint agreement with PG&E to develop, own and operate an underground natural gas storage facility near Fresno, California. Our 75 percent undivided ownership interest in the project is held by our wholly-owned subsidiary, Gill Ranch, which is also the sole operator of the project. The construction of this facility began in January 2010, and a majority of the construction work was completed by October 2010. Our portion of the initial development is designed to provide 15 Bcf of gas storage capacity by the end of 2013 and a 75 percent undivided interest in approximately 27 miles of gas transmission pipeline. Gill Ranch began operations during the fourth quarter of 2010. See Note 4.

Other

Our other business segment consists of NNG Financial, an investment in PGH, and other non-utility investments and business activities. NNG Financial had total assets of $1.1 million and $1.4 million as of December 31, 2010 and 2009, respectively, primarily reflecting a non-controlling minority interest in the Kelso-Beaver pipeline. Our net equity investment in PGH as of December 31, 2010 and 2009 was $14.8 million and $14.1 million, respectively. Total earnings from our other business segment as of December 31, 2010 and 2009 was net income of $0.3 million and $0.2 million, respectively. See Note 4.

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Consolidated Operations

Operations and Maintenance

Operations and maintenance expense was $121 million in 2010, compared to $127.1 million in 2009, a decrease of $6.1 million or 5 percent. The following summarizes the major factors that contributed to changes in operations and maintenance expense:

2010 compared to 2009:

- a $5.6 million decrease in utility payroll expense related to a reduced number of employees. There was a reduction of 105 employees or 9 percent over the two year period beginning January 2009;
- a $2.4 million decrease in utility bad debt expense (see below for further discussion);
- a $1.9 million decrease in pension expense, due to the increase in market value of plan investments from contributions in 2009 and 2010;
- a $1.5 million decrease in health care and other employee benefit expense due to reduced employee count;
- a $0.2 million decrease in damage claims in 2010.

Partially offsetting the above factors were:

- a $4.9 million increase in gas storage expenses, primarily related to start-up costs including salaries and benefits, power costs, legal fees and investment bank consulting costs; and
- a $1.0 million increase for consulting and legal fees at the utility related to a successful property tax appeal.

2009 compared to 2008:

- an $8.0 million increase in pension expense primarily due to lower assumed discount rates and a decrease in our plans' funded status, which resulted from a significant decline in the market value of assets during 2008;
- a $5.3 million increase in employee labor and benefit expense due to higher health care premiums and higher bonuses related to above-target operating results, which affect annual incentive payments and compensation;
- a $1.1 million charge related to our voluntary severance program involving workforce reductions during the third and fourth quarters of 2009;
- a $1.1 million increase in strategic initiatives including performance improvement and corporate tax projects; and
- a $1.0 million increase in utility bad debt expense (see discussion below).

Partially offsetting the above increases were:

- a $2.1 million decrease in employee compensation expense related to reduced employee count; and
- a $0.6 million decrease in claims in 2009.

Our bad debt expense as a percent of revenues was 0.21 percent for the year ended December 31, 2010, compared to 0.42 percent for the same period last year. The 2010 lower bad debt expense ratio was partly due to improved collections and increased recoveries from delinquent account balances. Credit risks are still somewhat high due to the weak economy and high unemployment rates, but our credit exposure has improved as evidenced by a decrease in delinquent account balances over last year. Lower customer usage from warmer than normal weather this past winter coupled with customer conservation, lower gas prices and low income energy assistance funds have contributed to our reduced credit exposure.

Health care costs have been trending higher, and it was recently reported that local and national health care cost increases were expected to be between 10 and 12 percent in 2011. Based on recent premium notices, we estimate that our employee health and welfare benefit costs for 2011 will increase by approximately 5 percent, including potential changes imposed by health care reform.

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In addition, our pension costs are expected to increase in 2011. However, effective January 1, 2011 the OPUC approved the deferral of utility pension expense above the amount recovered in rates, which was set in our last general rate case. The pension expense deferral will be recorded to a regulatory balancing account, and we expect it will result in a $4 to $5 million decrease in operations and maintenance expense for 2011. For further explanation of the pension balancing account, see "Regulatory Matters—Rate Mechanisms—Pension Deferral," above.

General Taxes

General taxes, which are principally comprised of property and payroll taxes and regulatory fees, decreased $4.4 million, or 16 percent, in 2010 compared to 2009, and increased $1.6 million, or 6 percent, in 2009 compared to 2008. The major factors that contributed to changes in general taxes are:

2010 compared to 2009:

- a $5.2 million refund of property taxes received in 2010 pursuant to a favorable ruling from the Oregon Supreme Court regarding taxation of utility gas inventory held for sale (see below for further discussion), partially offset by an increase in property taxes related to a 2 percent increase in net utility plant balances.

2009 compared to 2008:

- a $1.0 million or 5 percent increase in property taxes related to a 3 percent increase in net utility plant balances; and
- a $0.5 million increase in payroll taxes due to higher incentive compensation and employee severance compensation in 2009.

Over the past several years, we had been involved in litigation with the Oregon Department of Revenue over whether inventories held for sale were required to be taxed as personal property. In January 2010, the Oregon Supreme Court unanimously ruled in our favor, stating that these inventories were exempt from property tax. As a result of this ruling, we were entitled to a refund of approximately $5.2 million, plus accrued interest, for property taxes paid on inventories beginning with the 2002-03 tax year. We recognized a net $6.1 million increase in pre-tax income in the first quarter of 2010, which consisted of $5.2 million for the refund of property taxes, $1.9 million for accrued interest income, and $1.0 million of increased operations and maintenance expense for legal and consulting services. We received all of the property tax refunds.

Depreciation and Amortization

Total depreciation and amortization expense in 2010 increased by $2.3 million, or 4 percent, as compared to a $9.3 million or 13 percent decrease in 2009 over 2008. The increased expense in 2010 was primarily related to Gill Ranch going into service in the fourth quarter of 2010 plus the additional investments in utility plant for customer growth and system improvements. The decreased expense in 2009 was primarily related to the adoption of the new depreciation rates, which were approved by the OPUC, WUTC and FERC effective January 1, 2009 (see "Regulatory Matters—Rate Mechanisms," above).

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Other Income and Expense – Net

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

Thousands	2010	2009	2008
Gains from company-owned life insurance	$2,042	$3,416	$2,190
Interest income	2,024	211	250
Income from equity investments	588	1,329	667
Net interest on deferred regulatory accounts	4,692	2,051	552
Gain on sale of investments	223	45	1,737
Other non-operating	(2,467)	(3,338)	(1,650)
Total other income and expense - net	$7,102	$3,714	$3,746

2010 compared to 2009:

Other income and expense – net increased $3.4 million, primarily due to $1.9 million of interest income related to property tax refund plus a $2.6 million increase in interest from regulatory account balances largely due to smaller balances in gas costs between 2010 and 2009, partially offset by a $1.4 million decrease in income from life insurance due to higher policy gains realized in 2009.

2009 compared to 2008:

Other income and expense - net decreased by less than $0.1 million in 2009 over 2008. The decrease was primarily due to a net increase in other non-operating expense for higher business development costs and other strategic planning expense in 2009, and from a gain on sale of an aircraft realized in 2008. These were partially offset by increases in income from life insurance, income from our equity investment in Palomar and interest income from deferred regulatory account balances.

Interest Expense – Net

Interest expense—net of amounts capitalized in 2009 increased by $1.9 million, or 5 percent, compared to 2009, and increased in 2009 by $3.1 million, or 8 percent, compared to 2008. Increases in interest expense over the last two years reflect the issuance of long-term debt during 2009, which included $75 million of 5.37 percent medium term notes (MTN's) issued in March and $50 million of 3.95 percent MTN's issued in July, and higher short-term debt balances in 2010. Higher interest expense also reflects a lower average interest rate used in calculating the allowance for funds used during construction, which is referred to as AFUDC. AFUDC rates, comprised of short-term and long-term capital costs as appropriate, were 0.6 percent in 2010, 1.0 percent in 2009 and 3.6 percent in 2008.

Income Tax Expense

The increase in income tax expense of $2.8 million or 6 percent, compared to 2009 was primarily due to higher pre-tax consolidated earnings and an increase in our effective tax rate of 40.5 percent in 2010 compared to 38.3 percent in 2009. Income tax expense increased $6.0 million, or 15 percent, for the year ended December 31, 2009 compared to 2008, primarily due to higher pre-tax consolidated earnings and a slightly higher effective tax rate of 38.3 percent in 2009 compared to 36.9 percent in 2008.

For the 2010 tax year, the higher effective tax rate was primarily the result of increased amortization of our regulatory tax account on pre-1981 utility plant assets (see "Regulatory Matters—Rate Mechanisms," above) and a lower non-taxable gain on company-owned life insurance. For the 2009 tax year, the higher effective tax rate was primarily the result of an increase in the Oregon corporate income tax rate (see below for further discussion), an increased amortization of our regulatory tax asset account on pre-1981 plant assets, and an adjustment to deferred income taxes attributed to our non-regulated business segments. For more information on our income taxes, including a reconciliation between the statutory federal and state income tax rates and the effective rate, see Note 2 and Note 10.

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In July 2009, the governor of Oregon signed House Bill 3405 establishing increases in the state income tax rate for corporations, and Oregon voters approved this legislation in January 2010. The corporate income tax rate in Oregon increased from 6.6 percent to 7.9 percent for tax years 2009 and 2010 when taxable income is greater than $250,000. For tax years 2011 and 2012, the income tax rate will decrease to 7.6 percent, and for years after 2012 the tax rate will return to 6.6 percent, except for corporations with taxable income over $10 million the tax rate will remain at 7.6 percent. Following existing accounting guidance on income taxes, we re-measured our deferred income tax assets and liabilities, resulting in an adjustment to increase the balance by $3.6 million in 2009. Approximately $3.5 million of the adjustment was attributed to our utility operations. As we anticipate future recovery in rates, we recorded a $5.8 million regulatory asset for the grossed up revenue requirement. With respect to our non-utility business segments, a $0.1 million adjustment was charged to income tax expense in 2009.

On March 23, 2010, the Patient Protection and Affordable Care Act (the PPACA) was signed into law, and on March 30, 2010 the Health Care and Education Reconciliation Act of 2010 was signed into law. The PPACA changes the tax treatment of federal subsidies paid to sponsors of retiree health benefit plans that provide a benefit that is at least actuarially equivalent to the benefits under Medicare Part D. These subsidy payments become taxable in years beginning after December 31, 2012. Accounting guidance on income taxes requires the impact of this tax law change to be immediately recognized in the period that includes the enactment date. This provision of the PPACA did not have, and is not expected to have, an impact on our financial condition, results of operations or cash flows as we were not receiving federal subsidy payments under Medicare Part D.

Financial Condition

Capital Structure

One of our long-term goals 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 7 and 8). Achieving the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and have access to capital markets at reasonable costs. Our consolidated capital structure was as follows for the years ended December 31, 2010 and 2009:

	December 31,			
	2010		2009	
Common stock equity	44.7	%	47.2	%
Long-term debt	38.1	%	43.0	%
Short-term debt, including current maturities of long-term debt	17.2	%	9.8	%
Total	100	%	100	%

Liquidity and Capital Resources

At December 31, 2010, we had $3.5 million of cash and cash equivalents compared to $8.4 million at December 31, 2009. We also had $0.9 million in restricted cash invested at Gill Ranch as of December 31, 2010, compared to $35.5 million as of December 31, 2009, which was being held as collateral for equipment purchase contracts and construction loans. In order to maintain sufficient liquidity during periods of volatile capital markets, at times we will maintain higher cash balances, add short-term borrowing capacity, and pre-fund utility capital expenditures while long-term fixed rate environments are attractive. Our short-term liquidity is supported by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, committed multi-year credit facilities, cash available from 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 utility capital expenditures, refinance maturing short-term and long-term debt and provide for general corporate purposes. In March 2009, we issued $75 million of secured MTNs with an interest rate of 5.37 percent and a maturity date of February 1, 2020. In July 2009, we issued $50 million of secured MTNs with an interest rate of 3.95 percent and a maturity date of July 15, 2014.

The capital markets in the last two years, including the commercial paper market, experienced significant volatility and tight credit conditions, but conditions over the past 12 months improved as reflected by tighter credit spreads and increased access to new financing for investment grade issuers. With our current debt ratings (see “Credit Ratings,” below), we have been able to issue commercial paper and MTNs at attractive rates and have not needed to borrow from our back-up credit facilities. In the event that we are not able to issue new debt due to market conditions, we expect that our near term liquidity needs can be met by using cash balances or drawing upon our committed credit facilities. We also have a universal shelf registration filed with the Securities and Exchange Commission for the issuance of secured and unsecured debt or equity securities, subject to market conditions and regulatory approvals. We have OPUC approval to issue up to $175 million of additional MTNs under the existing shelf registration, which was filed in January 2011.

In the event that our senior unsecured long-term debt credit ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, 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 cash requirements and may trigger significant increases in short-term borrowings. If the credit risk-related contingent features underlying these contracts were triggered on December 31, 2010, we could have been required to post $27.3 million of collateral to our counterparties, but that assumes our long-term debt ratings were at non-investment grade levels (see Note 13 and “Credit Ratings,” below).

Recent developments that may have an impact on our liquidity and capital resources include pension contributions, tax benefits and environmental expenditures and insurance recoveries. With respect to pension requirements, we expect to make additional contributions in 2011 and in future years until we are fully funded under the Pension Protection Act rules (see “Pension Cost and Funding Status of Qualified Retirement Plans,” below). With respect to federal income tax liabilities, an extension was granted that allows us to take 50 percent bonus depreciation on a majority of our capital expenditures in 2010, and 100 percent bonus depreciation on qualified expenditures during 2011, which will significantly reduce our tax liability for the 2010 and 2011 tax years thereby providing cash flow benefits in late 2010 and 2011 (see “Cash Flows—Operating Activities,” below). And with respect to environmental liabilities, we expect to continue using cash resources to fund our environmental liabilities, but we also anticipate recovering amounts through insurance or utility rates over the next several years, although the amount and timing of these expenditures and recoveries is uncertain (see Note 15).

In addition, Gill Ranch began commercial operations in October 2010. Although we anticipate future operating cash flows, the amount and timing of these cash flows are uncertain.

In July 2010, the U.S. Congress passed and President Obama signed into law the “Wall Street Reform and Consumer Protection Act.” The new legislation will require additional government regulation of derivative and over-the-counter transactions, and could expand collateral requirements. While we are currently evaluating the new legislation to determine its impact, if any, on our hedging procedures, results of operations, financial position and liquidity, we do not expect to know the full impact of the legislation until final regulations implementing the legislation are issued.

Based on several factors, including our current credit ratings, recent experience issuing commercial paper, current cash reserves, committed credit facilities and other liquidity resources, and our expected ability to issue long-term debt in the form of an MTN program under our universal shelf registration, we believe our liquidity is sufficient to meet anticipated near-term cash requirements, including all contractual obligations and investing and financing activities discussed below.

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Dividend Policy

We have paid quarterly dividends on our common stock each year since the stock was first issued to the public in 1951. Annual common stock dividend payments per share, adjusted for stock splits, have increased each year since 1956. The amount and timing of dividends payable on our common stock is within the sole discretion of our Board of Directors. Subject to Board approval, we expect to continue paying quarterly cash dividends on common stock. However, the declarations and amount of future dividends will depend upon our earnings, cash flows, financial condition and other factors including Board approval.

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, 2010 by maturity and type of obligation.

	Payments Due in Years Ending December 31,						
Thousands	2011	2012	2013	2014	2015	Thereafter	Total
Commercial paper	$ 257,435	$ -	$ -	$ -	$ -	$ -	$ 257,435
Long-term debt maturities	10,000	40,000	-	60,000	40,000	451,700	601,700
Interest on long-term debt	36,840	34,518	33,607	33,446	31,951	249,817	420,179
Postretirement benefit payments(1)	20,741	21,198	21,492	22,131	22,719	128,733	237,014
Capital leases	482	330	178	9	-	-	999
Operating leases	4,984	4,937	4,909	5,152	5,034	28,169	53,185
Gas purchase contracts(2)	111,514	19,310	13,684	11,404	-	-	155,912
Gas pipeline commitments	90,510	56,610	48,953	25,059	17,853	253,254	492,239
Other purchase commitments(3)	51,511	3,284	638	-	-	-	55,433
Total	$ 584,017	$ 180,187	$ 123,461	$ 157,201	$ 117,557	$ 1,111,673	$ 2,274,096

(1) The majority of postretirement benefit payments are related to our qualified defined benefit pension plans, which are funded by plan assets and future cash contributions. See Note 9.
(2) All gas purchase contracts use price formulas tied to monthly index prices. Commitment amounts are based on index prices at December 31, 2010.
(3) Excludes a noncash Gill Ranch agreement for $13.5 million of cushion gas.

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.

At December 31, 2010, 607 of our utility employees were members of the Office and Professional Employees International Union, Local No. 11. In July 2009, our union employees ratified a new five-year labor agreement called the Joint Accord. The agreement included a scheduled 1 percent wage increase each year, with the potential for up to an additional 2 percent per year based on wage inflation and other factors. The Joint Accord also maintains competitive health benefits while limiting the cost increases for these benefits to the same level as the annual wage increases, and provides increased job flexibility along with the ability for the Company to use short-term unpaid leave to temporarily adjust the workforce without layoffs. The Joint Accord continues our defined benefit retirement plan and post retiree medical for existing union employees as of December 31, 2009, but closes the plan to new employees hired after December 31, 2009. The term of the new Joint Accord extends to May 31, 2014, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement.

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Short-term Debt

Our primary source of utility short-term liquidity is from internal cash flows and the sale of commercial paper. In addition to issuing commercial paper to meet working capital requirements, including seasonal requirements to finance gas inventories and accounts receivable, short-term debt may also be used to temporarily fund utility 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 Agreements," below). Our commercial paper program did not experience any liquidity disruptions as a result of the credit problems that affected issuers of asset-backed commercial paper and certain other commercial paper programs over the last several years. At December 31, 2010 and 2009, our utility had commercial paper outstanding of $257.4 million and $69.8 million, respectively. The effective interest rate on the utility's commercial paper outstanding at December 31, 2010 and 2009 was 0.4 percent and 0.3 percent, respectively.

In March 2009, Gill Ranch entered into a cash collateralized credit facility for up to $40 million, which was extended through September 30, 2010. In June 2010, Gill Ranch repaid its $40 million bank loan outstanding using the proceeds from its cash collateralized account. The effective interest rate on the Gill Ranch credit facility was 0.8 percent during 2010.

Credit Agreements

We have a syndicated multi-year credit agreement for unsecured revolving loans totaling $250 million, which may be extended for additional one-year periods subject to lender approval. All lenders agreed to extend the original term for an additional one-year period through May 31, 2013. We also have three bilateral credit agreements totaling $50 million in effect from November 30, 2010 through March 31, 2011. All lenders under our syndicated and bilateral credit agreements are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2010 as follows:

	Loan Commitment Amounts in Thousands	
Lender rating, by category	Syndicated Facility	Bilateral Facility
AAA/Aaa	$ -	$ -
AA/Aa	230,000	50,000
A/A	20,000	-
BBB/Baa	-	-
Total	$ 250,000	$ 50,000

Based on credit market conditions, 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 our lenders' creditworthiness, including a review of capital ratios, credit default swap spreads and credit ratings, we believe the risk of lender default is minimal.

As discussed above, we extended commitments with all seven lenders under the syndicated agreement, with commitments totaling $250 million, to May 31, 2013. The syndicated 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 maturity date of the credit agreement. The syndicated 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 syndicated and bilateral agreements are due and payable on or before the maturity date. There were no outstanding balances under these credit agreements at December 31, 2010 and 2009. These agreements also require 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, 2010 and 2009, with consolidated indebtedness to total capitalization ratios of 55.4 percent and 52.8 percent, respectively.

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The syndicated and bilateral agreements also require that we maintain credit ratings with Standard & Poor's (S&P) and Moody's Investors Service (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 by S&P or by Moody's 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, a change in our debt rating below BBB- or Baa3 would require additional approval from the OPUC prior to issuance of debt, and interest rates on any loans outstanding under the credit agreements are tied to debt ratings, which would increase or decrease the cost of any loans under the credit agreements when ratings are changed (see "Credit Ratings," below).

All three lenders under the short-term credit agreements are existing lenders under our syndicated credit agreement. The short-term credit agreements require us to comply with the terms and conditions of the syndicated credit agreement and give the lenders under the short-term credit agreements the same rights with respect to the short-term credit agreements that they have under the syndicated credit agreement.

Credit Ratings

Our debt credit ratings are a factor in our liquidity, affecting our access to the capital markets, including the commercial paper market. Our debt credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts. A change in our ratings below BBB- by S&P or Baa3 by Moody's would require additional approval from the OPUC prior to our issuing additional long-term debt.

The following table summarizes our current debt ratings from S&P and Moody's:

	S&P	Moody's
Commercial paper (short-term debt)	A-1	P-1
Senior secured (long-term debt)	A+	A1
Senior unsecured (long-term debt)	n/a	A3
Corporate credit rating	A+	n/a
Ratings outlook	Stable	Stable

The above 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.

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Redemptions of Long-Term Debt

We redeemed MTN's during 2010, 2009 and 2008 as follows:

	Amounts Redeemed		
Thousands (Years ended December 31)	2010	2009	2008
Medium-Term Notes			
6.50% Series B due 2008	$-	$-	$5,000
6.65% Series B due 2027 (1)	-	300	-
4.11% Series B due 2010	10,000	-	-
7.45% Series B due 2010	25,000	-	-
	$35,000	$300	$5,000

(1) In November 2009, $0.3 million of our 6.65 percent secured MTNs due 2027 were redeemed pursuant to a one-time put option. This one-time put option has now expired, and the $19.7 million remaining principal outstanding is expected to be paid at maturity in November 2027.

Cash Flows

Operating Activities

2010 compared to 2009:

For the year ended December 31, 2010, cash flow from operating activities totaled $126.5 million compared to $240.3 million in 2009 and $34.7 million in 2008. The significant factors contributing to changes in operating cash flow in 2010 compared to 2009 are as follows:

- an increase of $39.6 million from deferred income taxes, primarily reflecting higher tax benefits from bonus depreciation taken in 2010 related to Gill Ranch capital investments placed in service;
- an increase of $15.0 million from a smaller pension contribution in 2010 compared to 2009;
- an increase of $10.1 million from the 2009 settlement of an interest rate hedge;
- a decrease of $75 million from accrued taxes, primarily related to 2010 benefits that will be refunded in 2011, and due to tax refunds received in 2009 related to a change in tax accounting method for repairs and maintenance costs;
- a decrease of $62.9 million from changes in deferred gas cost regulatory account which reflects actual gas prices compared to estimated gas prices embedded in customer rates;
- a decrease of $19.7 million from changes in receivables primarily due to higher balances at the end of 2008, which benefitted cash flows during 2009;
- a decrease of $14.5 million from changes in inventories primarily due to higher price of gas in inventory at the end of 2008, which benefitted cash flows during 2009 as higher cost inventories were recovered through utility rates; and
- a decrease of $13.0 million in accounts payable due to decreased Gill Ranch construction activity at the end of 2010 compared to the end of 2009.

In September 2010, Congress passed the Unemployment Insurance, Reauthorization and Job Creation Act of 2010 (the Act) and the legislation was signed into law by President Obama. The Act extends for one additional year the temporary bonus depreciation rules first enacted in the Economic Stimulus Act of 2008 and subsequently renewed in the American Recovery and Reinvestment Act of 2009. Under the bonus depreciation provision, an additional first-year tax deduction is allowed for depreciation equal to 50 percent of the adjusted basis of qualified property through September 8, 2010, and 100 percent through December 31, 2011, in the year the property is placed in service, and the remaining percentage recovered under the normal depreciation rules. The 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. As a result of this extension, we will recognize an increase in our cash flow by reducing our current tax liabilities for the 2010 and 2011 tax years. Any deductions in excess of income for federal income tax purposes will be carried back to the 2009 tax year. As of December 31, 2010, we have a federal and state income tax receivable balance of $41.1 million, which we expect to realize in cash flows during 2011.

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2009 compared to 2008:

In 2009, cash flow from net income and operating activity adjustments, excluding working capital changes, increased $29.1 million compared to 2008. Working capital changes in 2009 increased $176.5 million compared to the same period in 2008. The total change in cash flow from operating activities was an increase of $205.6 million. The significant factors contributing to the operating cash flow changes between 2009 and 2008 are as follows:

- an increase of $82.1 million from deferred gas cost savings reflecting lower actual gas prices compared to gas prices collected in customer rates in 2009, net of amounts already refunded to customers (see below);
- an increase of $72.0 million from decreases in accounts receivable and accrued unbilled revenue primarily due to the collection of higher balances in accounts receivable and accrued unbilled revenue balances at year end 2008;
- an increase of $41.6 million from income tax refunds received from a change in tax accounting method for certain repairs and maintenance costs (see below);
- an increase of $31.2 million related to the net decrease in gas inventory balances due to the higher price of gas injected into storage in 2008;
- an increase of $25.7 million from accounts payable, reflecting lower gas prices at the end of 2009 compared to 2008;
- a decrease of $25.0 million related to our pension contributions in 2009 to reduce our unfunded liability;
- a decrease of $13.4 million from deferred income taxes, reflecting the approved tax deduction for repair and maintenance costs (see below); and
- a decrease of $10.1 million related to the loss realized on the settlement of our interest rate hedge in 2009.

In June and July of 2009, we refunded $35.8 million to our Oregon and Washington customers for the customers' share of accumulated gas cost savings from November 1, 2008 through March 31, 2009. This reduction in cash was part of the gas cost savings accumulated from lower gas prices during the 2008-09 gas contract year. Additional savings for Oregon and Washington customers accumulated, and these amounts were refunded to customers through lower rates starting November 1, 2009 and November 1, 2010.

In December 2008, we filed an application with the IRS that requested a change in our tax accounting method to expense routine repair and maintenance costs for gas pipelines that are currently being capitalized and depreciated for book purposes. The IRS consented to our request in August 2009, and we recognized a tax deduction of approximately $59 million on our 2008 tax return, which resulted in a federal tax refund of approximately $21 million during the fourth quarter of 2009.

At December 31, 2008, we reported 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 Economic Stimulus Act. As a result of the change in our tax accounting method for repair and maintenance costs discussed above as well as our increased pension contribution, our NOL for federal and Oregon income tax purposes was $89.0 million and $87.2 million on our 2008 federal and Oregon tax returns, respectively. The federal NOL was carried back to 2006 for a refund of taxes paid in prior years, while the Oregon NOL has been carried forward to reduce current and future taxable income. We anticipate that we will be able to use all loss carryforwards in future years. The 2008 Oregon NOL was fully utilized in 2009.

We have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations. For information on cash flow requirements related to leases and other purchase commitments, see "Contractual Obligations," above and Note 15.

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Investing Activities

Cash used in investing activities for the year ended December 31, 2010 totaled $212.9 million, up from $162.1 million for the same period in 2009. Our capital expenditures were $248.5 million in the year ended December 31, 2010, up from $135.1 million for the same period in 2009. Utility capital expenditures decreased $14.6 million in 2010 primarily due to our automated meter reading project that was completed in 2009, while our non-utility capital expenditures increased $128.1 million primarily due to construction at Gill Ranch.

Cash used in investing activities during 2010 was partially offset by the release of restricted cash, which had collateralized equipment purchase contracts and bank loans for Gill Ranch. Restricted cash increased $65.1 million compared to 2009, due to settling our cash collateralized loan in June 2010.

In 2011, capital expenditures are estimated to be between $95 million and $105 million for the utility, and between $5 million and $15 million for non-utility development projects that are currently in process (see "Strategic Opportunities," above). Over the five-year period 2011 through 2015, total utility capital expenditures are estimated at between $400 and $500 million. The estimated level of utility capital expenditures over the next five years reflects assumptions for customer growth, storage development at Mist for the utility, technology investments and utility distribution improvements, including requirements under the current Pipeline Safety programs. 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.

Cumulatively at December 31, 2010, we have spent a total of $214.7 million in capital costs at Gill Ranch, including $3.2 million of construction work-in-progress.

In 2011, Palomar expects to continue working on the planning and permitting phase of the east segment of the proposed pipeline. The incremental cost to obtain the appropriate permits is estimated to be $10 million, of which our ownership interest is 50 percent. The initial planning and permitting costs are being financed with equity funds from us and our partner, GTN. Also, Northwest Pipeline has contributed some funding toward planning and permitting costs in accordance with the terms of the MOU. For more information, see Note 12 and "Strategic Opportunities—Pipeline Diversification," above.

Financing Activities

Cash provided by financing activities for the year ended December 31, 2010 totaled $81.4 million, up from cash used of $76.7 million for the same period in 2009. Our short-term debt balances increased $155.4 million for the year ended December 31, 2010, compared to a decrease of $158.9 million for the same period in 2009, which was partially driven by our long-term debt issuances of $125 million in 2009. We use long-term debt proceeds primarily to finance capital expenditures, refinance short-term and long-term debt maturities as well as for general corporate purposes.

We have a repurchase program approved through May 2011 which provides authorization to repurchase up to 2.8 million shares or up to $100 million. The purchases are made in the open market or through privately negotiated transactions. No repurchases were made in 2010, 2009 or 2008 under the program. 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, at the average price of $39.19 per share (see Part II, Item 5, "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities," above).

In 2010, we produced negative free cash flow of $131.1 million, compared to positive free cash flow of $35.8 million in 2009 and negative free cash flow of $115.3 million in 2008. 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.

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Thousands	2010	2009	2008
Cash provided by operating activities	$126,469	$240,335	$34,721
Cash used in investing activities	(212,871)	(162,141)	(109,825)
Cash dividend payments on common stock	(44,652)	(42,415)	(40,178)
Free cash flow	$(131,054)	$35,779	$(115,282)

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

Pension Cost and Funding Status of Qualified Retirement Plans

Pension costs are determined in accordance with accounting standards for compensation and retirement benefits (see "Application of Critical Accounting Policies and Estimates – Accounting for Pensions and Postretirement Benefits," above). Pension costs for our two qualified defined benefit plans, which are allocated between operation expenses and capital expenditures based on employee payroll distributions, totaled $11.4 million in 2010, a decrease of $3.2 million from 2009.

The fair market value of pension assets in these two plans increased to $219.0 million at December 31, 2010 from $201.3 million at December 31, 2009. The increase was due to a positive return on plan assets of $24.7 million and a $10.0 million employer contribution, partially offset by benefit payments of $17.0 million.

We make contributions to company-sponsored qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Our qualified defined benefit pension plans were underfunded by $95.4 million at December 31, 2010. In March 2010, we contributed $10 million to these plans, with a portion allocated to 2009 and 2010 plan years. We plan to make contributions during 2011 of approximately $22 million. For more information on the funding status of our qualified retirement plans and other postretirement benefits, see Note 9.

We also contribute to a multiemployer pension plan (Western States Plan) pursuant to our collective bargaining agreement. We made contributions totaling $0.4 million to the Western States Plan in both 2010 and 2009.   See Note 9 for further discussion.

Ratios of Earnings to Fixed Charges

For the years ended December 31, 2010, 2009 and 2008, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 3.73, 3.86, and 3.76, 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. See Exhibit 12.

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 accounting standards for contingencies (see "Application of Critical Accounting Policies and Estimates," above). At December 31, 2010, we had a regulatory asset of $114.3 million for deferred environmental costs, which includes $55.6 million for additional costs expected to be paid in the future and accrued interest of $14 million. If it is determined that both the insurance recovery and future customer rate recovery of such costs are 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 15.

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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 2.

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 our Mist storage facility, 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.

Commodity Price and Storage Value Risk

Natural gas commodity prices and storage values are subject to market fluctuations due to unpredictable factors including weather, pipeline transportation congestion, drilling technologies, potential market speculation and other factors that affect short-term supply and demand. In addition to managing storage positions through a combination of short- and long-term fixed price contracts, 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 for utility gas purchases. These financial hedge contracts are generally included in our annual PGA filing for recovery, subject to a regulatory prudence review. We regularly monitor and manage the financial exposure and liquidity risk of our storage positions and financial hedge contracts.

Interest Rate Risk

We are exposed to interest rate risk primarily 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.

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, 2010 and 2009, notional amounts under foreign currency forward contracts totaled $13.9 million and $6.6 million, respectively. As of December 31, 2010 , all foreign currency forward contracts mature within one year. If all of the foreign currency forward contracts had been settled on December 31, 2010, a gain of $0.1 million would have been realized (see Note 13).

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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 an adverse effect on our financial condition or results of operations.

Credit exposure to financial derivative counterparties. Based on estimated fair value at December 31, 2010, our overall credit exposure relating to commodity hedge contracts is considered to be immaterial as it reflects amounts we owed to our financial derivative counterparties totaling $52.7 million. However, changes in natural gas prices could result in counterparties owing us money. Therefore our financial derivatives policy requires counterparties to have at least an 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. Due to potential changes in market conditions and credit concerns, we continue to enforce strong credit requirements. We actively monitor and manage our derivative credit exposure and place counterparties on hold for trading purposes or require cash collateral, letters of credit or guarantees as circumstances warrant. As of December 31, 2010, we do not have any actual derivative credit risk exposure, which reflects amounts that financial derivative counterparties owe to us.

The following table summarizes our overall 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	2010	2009
AAA/Aaa	$ -	$ -
AA/Aa	(43,656)	(15,792)
A/A	(9,017)	-
BBB/Baa	-	-
Total	$ (52,673)	$ (15,792)

In most cases, we also mitigate the credit risk of financial derivatives by having master netting arrangements with our counterparties which 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.

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Credit exposure to insurance companies for environmental damage claims. We regularly monitor the financial condition of insurance companies who provide general liability insurance policy coverage to NW Natural and its predecessors with respect to environmental damage claims. We have filed claims for our environmental costs with a number of insurance companies. The majority of these companies have credit ratings of A- or better from A.M. Best Co. (AM Best). AM Best is a global independent credit rating agency who has provided quantitative and qualitative analysis of insurance company balance sheet strength for over 100 years. AM Best uses a rating scale that ranges from A++ ("Superior" financial strength) to F ("In Liquidation"), with a rating of A- considered "Excellent." A strong credit rating from AM Best is not a guarantee that an insurance company will be able to meet its contractual obligations. The remaining insurance companies who do not have credit ratings of A- or better are expected to have sufficient funds in reserves to cover these claims. Our credit exposure to insurance companies for environmental claims, which reflects amounts we believe are owed to us, could be material. In the event we are unable to recover environmental expenses from these insurance policies, we will seek recovery of unreimbursed amounts through customer rates.

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, 2010, approximately 9 percent of our Oregon customers had opted out. In addition to the Oregon customers opting out, our Washington residential and commercial customers account for approximately 10 percent of our total customer base and are not covered by weather normalization. The combination of Oregon and Washington customers not covered by a weather normalization mechanism is less than 20 percent of all residential and commercial customers.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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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

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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 our internal control over financial reporting as of December 31, 2010. 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 we maintained effective internal control over financial reporting as of December 31, 2010.

The effectiveness of internal control over financial reporting as of December 31, 2010 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 25, 2011

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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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 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, 2010, 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.

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 25, 2011

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF INCOME

Thousands, except per share amounts (year ended December 31)	2010	2009	2008
Operating revenues:			
Gross operating revenues	$812,106	$1,012,711	$1,037,855
Less: Cost of sales	424,534	611,168	656,568
Revenue taxes	19,991	24,656	25,072
Net operating revenues	367,581	376,887	356,215
Operating expenses:			
Operations and maintenance	120,980	127,104	113,360
General taxes	23,872	28,253	26,660
Depreciation and amortization	65,124	62,814	72,159
Total operating expenses	209,976	218,171	212,179
Income from operations	157,605	158,716	144,036
Other income and expense - net	7,102	3,714	3,746
Interest expense - net	42,578	40,637	37,579
Income before income taxes	122,129	121,793	110,203
Income tax expense	49,462	46,671	40,678
Net income	$72,667	$75,122	$69,525
Average common shares outstanding:			
Basic	26,589	26,511	26,438
Diluted	26,657	26,576	26,594
Earnings per share of common stock:			
Basic	$2.73	$2.83	$2.63
Diluted	$2.73	$2.83	$2.61
Dividends declared per share of common stock	$1.68	$1.60	$1.52

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2010	2009
Assets:		
Current assets:		
Cash and cash equivalents	$3,457	$8,432
Restricted cash	924	35,543
Accounts receivable	67,969	77,438
Accrued unbilled revenue	64,803	71,230
Allowance for uncollectible accounts	(2,950)	(3,125)
Regulatory assets	52,714	29,954
Derivative instruments	2,245	6,504
Inventories:		
Gas	70,672	71,672
Materials and supplies	9,713	9,285
Income taxes receivable	41,066	-
Other current assets	19,652	21,302
Total current assets	330,265	328,235
Non-current assets:		
Property, plant and equipment	2,576,402	2,362,734
Less accumulated depreciation	722,239	692,600
Total property, plant and equipment - net	1,854,163	1,670,134
Regulatory assets	348,897	316,536
Derivative instruments	628	843
Other investments	69,094	67,365
Other non-current assets	13,569	16,139
Total non-current assets	2,286,351	2,071,017
Total assets	$2,616,616	$2,399,252

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2010	2009
Capitalization and liabilities:		
Capitalization:		
Common stock - no par value; authorized 100,000 shares; issued and outstanding 26,668 and 26,533 at December 31, 2010 and 2009, respectively	$342,978	$337,361
Retained earnings	356,727	328,712
Accumulated other comprehensive income (loss)	(6,604)	(5,968)
Total common stock equity	693,101	660,105
Long-term debt	591,700	601,700
Total capitalization	1,284,801	1,261,805
Current liabilities:		
Short-term debt	257,435	102,000
Current maturities of long-term debt	10,000	35,000
Accounts payable	93,243	123,729
Taxes accrued	10,579	21,037
Interest accrued	5,182	5,435
Regulatory liabilities	17,828	46,628
Derivative instruments	38,437	19,643
Other current liabilities	35,457	39,097
Total current liabilities	468,161	392,569
Deferred credits and other non-current liabilities:		
Deferred tax liabilities	373,409	300,898
Regulatory liabilities	258,031	248,622
Pension and other postretirement benefit liabilities	144,250	127,687
Derivative instruments	17,022	3,193
Other non-current liabilities	70,942	64,478
Total deferred credits and other non-current liabilities	863,654	744,878
Commitments and contingencies (see Note 15)	-	-
Total capitalization and liabilities	$2,616,616	$2,399,252

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CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY AND COMPREHENSIVE INCOME

Thousands	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity	Comprehensive Income
Balance at Dec. 31, 2007	$ 331,595	$ 266,658	$ (3,502)	$ 594,751	
Net Income	-	69,525	-	69,525	$ 69,525
Change in unrealized loss from derivatives	-	-	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 ($140) 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
Net Income	-	75,122	-	75,122	$ 75,122
Change in non-qualified employee benefit plan liability, net of $1,273 of tax	-	-	(1,936)	(1,936)	(1,936)
Amortization of non-qualified employee benefit plan liability, net of ($58) of tax	-	-	354	354	354
Restricted stock amortizations	39	-	-	39	
Dividends paid on common stock	-	(42,415)	-	(42,415)	
Tax benefits from employee stock option plan	229	-	-	229	
Stock-based compensation	(776)	-	-	(776)	
Issuance of common stock	1,115	-	-	1,115	
Balance at Dec. 31, 2009	337,361	328,712	(5,968)	660,105	$ 73,540
Net Income	-	72,667	-	72,667	$ 72,667

Change in non-qualified employee benefit plan liability, net of $674 of tax	-	-	(1,027)	(1,027)	(1,027)
Amortization of non-qualified employee benefit plan liability, net of ($257) of tax	-	-	391	391	391
Dividends paid on common stock	-	(44,652)	-	(44,652)	
Tax expense from employee stock option plan	(125)	-	-	(125)	
Stock-based compensation	554	-	-	554	
Issuance of common stock	5,188	-	-	5,188	
Balance at Dec. 31, 2010	$ 342,978	$ 356,727	$ (6,604)	$ 693,101	$ 72,031

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CONSOLIDATED STATEMENTS OF CASH FLOWS

Thousands (year ended December 31)	2010	2009	2008
Operating activities:			
Net income	$72,667	$75,122	$69,525
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	65,124	62,814	72,159
Undistributed earnings from equity investments	(588)	(1,329)	(667)
Non-cash expenses related to qualified defined benefit pension plans	8,009	9,914	2,855
Contributions to qualified defined benefit pension plans	(10,000)	(25,000)	-
Deferred environmental expenditures	(7,826)	(10,069)	(8,179)
Settlement of interest rate hedge	-	(10,096)	-
Other	(2,265)	(3,461)	(2,190)
Changes in assets and liabilities:			
Receivables	15,830	35,506	(36,493)
Inventories	572	15,110	(16,123)
Taxes accrued	(51,524)	23,461	(21,493)
Accounts payable	(11,846)	1,188	(24,540)
Interest accrued	(253)	8,582	(42)
Deferred gas costs	(26,090)	36,819	(45,291)
Deferred tax liabilities	76,410	36,775	50,192
Other - net	(1,751)	(15,001)	(4,992)
Cash provided by operating activities	126,469	240,335	34,721
Investing activities:			
Capital expenditures	(248,505)	(135,124)	(103,998)
Restricted cash	34,619	(30,524)	(5,006)
Other	1,015	3,507	(821)
Cash used in investing activities	(212,871)	(162,141)	(109,825)
Financing activities:			
Common stock issued - net	4,598	(375)	2,310
Long-term debt issued	-	125,000	-
Long-term debt retired	(35,000)	(300)	(5,000)
Change in short-term debt	155,435	(158,851)	117,751
Cash dividend payments on common stock	(44,652)	(42,415)	(40,178)
Other	1,046	263	1,030
Cash provided by (used in) financing activities	81,427	(76,678)	75,913
Increase (decrease) in cash and cash equivalents	(4,975)	1,516	809
Cash and cash equivalents - beginning of period	8,432	6,916	6,107
Cash and cash equivalents - end of period	$3,457	$8,432	$6,916
Supplemental disclosure of cash flow information:			
Interest paid	$41,037	$36,762	$37,669
Income taxes paid	$22,600	$10,000	$12,300

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Organization and Principles of Consolidation

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), primarily consisting of our regulated gas distribution business and our gas storage business, which includes our subsidiary Gill Ranch Storage, LLC (Gill Ranch), NW Natural Gas Storage, LLC (NWN Gas Storage), a wholly-owned subsidiary of our subsidiary NW Natural Energy, LLC, and other investments and business activities, which primarily consist of our wholly-owned subsidiary NNG Financial Corporation (NNG Financial) and an equity investment in Palomar Gas Holdings, LLC (PGH) that is developing a proposed natural gas transmission pipeline through its wholly-owned subsidiary Palomar Gas Transmission LLC (Palomar) (see Note 4). Investments in corporate joint ventures and partnerships in which we are not the primary beneficiary are accounted for by the equity method or the cost method.

In this report, the term "utility" is used to describe our regulated gas distribution business, and the term "non-utility" is used to describe our gas storage business and other non-utility investments and business activities (see Note 4). Intercompany accounts and transactions have been eliminated, except for transactions required to be included under regulatory accounting standards to reflect the effect of such regulation.

Certain prior year balances in our consolidated financial statements have been combined or reclassified to conform with the current presentation. These changes had no impact on our prior year's consolidated results of operations and no material impact on financial condition or cash flows.

2. Summary of Significant Accounting Policies

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America (U.S. 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 most likely 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 Public Utility Commission of Oregon (OPUC) and Washington Utilities and Transportation Commission (WUTC), and gas storage services, which are regulated by the Federal Energy Regulatory Commission (FERC), the California Public Utilities Commission (CPUC) 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 U.S. GAAP. Our businesses regulated by the OPUC, WUTC and FERC earn a reasonable return on invested capital from approved cost-based rates, while our business regulated by the CPUC earns a return to the extent we are able to charge competitive prices above our costs (i.e. market-based rates).

In applying regulatory accounting principles, 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 in most cases.

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At December 31, 2010 and 2009, the amounts deferred as regulatory assets and liabilities were as follows:

	Current	
Thousands	2010	2009
Regulatory assets:		
Unrealized loss on derivatives(1)	$38,437	$19,643
Pension and other postretirement benefit liabilities(2)	10,988	7,502
Other(3)	3,289	2,809
Total regulatory assets	$52,714	$29,954
Regulatory liabilities:		
Gas costs payable	$15,583	$37,055
Unrealized gain on derivatives(1)	2,245	6,504
Other(3)	-	3,069
Total regulatory liabilities	$17,828	$46,628

	Non-Current	
Thousands	2010	2009
Regulatory assets:		
Unrealized loss on derivatives(1)	$17,022	$3,193
Income tax asset	72,341	76,240
Pension and other postretirement benefit liabilities(2)	118,248	109,932
Environmental costs - paid(4)	58,728	46,204
Environmental costs - accrued but not yet paid(4)	55,583	59,844
Other(3)	26,975	21,123
Total regulatory assets	$348,897	$316,536
Regulatory liabilities:		
Gas costs payable	$2,297	$6,915
Unrealized gain on derivatives(1)	628	843
Accrued asset removal costs	252,941	238,757
Other(3)	2,165	2,107
Total regulatory liabilities	$258,031	$248,622

(1) An unrealized gain or loss on 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) Certain pension and other postretirement benefit liabilities are approved for regulatory deferral. Such amounts are recoverable in rates, including an interest component, when recognized in net periodic benefit costs (see Note 9).

(3) 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.

(4) 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.

The amortization period for our regulatory assets and liabilities ranges from less than one year to an undeterminable period. Our regulatory liabilities for gas costs payable are generally amortized over 12 months beginning each November 1 following the gas contract year during which the deferred gas costs are realized. Similarly, most of our regulatory deferred accounts are amortized over 12 months. However, certain regulatory account balances, such as income taxes, environmental costs, pension liabilities and accrued asset removal costs, are large and tend to be amortized over longer periods once we have agreed upon an amortization period with the respective regulatory agency.

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We believe that continued application of regulatory accounting for regulated activities is appropriate and consistent with the current regulatory environment, and that all regulated assets and liabilities at December 31, 2010 and 2009 will be recoverable or refundable through future rate making decisions. We annually review all regulatory assets and liabilities 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 regulatory accounting, then we would be required to write off the net unrecoverable balances against earnings.

New Accounting Standards

Adopted Standards

Variable Interest Entity. Effective January 1, 2010, we adopted the amended authoritative guidance on variable interest entities (VIE). This guidance requires a continuing analysis to determine whether an entity has a controlling financial interest and whether it is the primary beneficiary. As the primary beneficiary with a controlling financial interest we would be required to consolidate the VIE in our financial statements. The guidance defines the primary beneficiary as the entity having:

- power to control the activities that most significantly impact performance; and
- the obligation to absorb losses or right to receive benefits from the entity that could potentially be significant to the VIE.

Although we do have an ownership interest in PGH, which is a VIE, we are not the primary beneficiary and therefore not required to consolidate PGH in the accompanying financial statements. The adoption of this standard has not had a material effect on our financial condition, results of operations or cash flows. See Note 12 for further information.

Recent Accounting Pronouncements

Fair Value Disclosures. In January 2010, the Financial Accounting Standards Board issued authoritative guidance on new fair value measurements and disclosures. This guidance requires additional disclosures for fair value measurements that use significant assumptions not observable in active markets (i.e. level 3 valuations) including a rollforward schedule. These changes are effective for periods beginning after December 15, 2010; however, we elected to early adopt these disclosure requirements, as shown in Note 9. The adoption of this standard did not have, and 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 11). In accordance with regulatory accounting, the cost of constructing long-lived utility plant and gas storage assets generally includes an allowance for funds used during construction (AFUDC) or capitalized interest. AFUDC represents the regulatory financing cost incurred when debt and equity funds are used for construction (see "Allowance for Funds Used During Construction," below). When gas storage assets are expected to be subject to market-based rates, then the financing cost incurred during construction includes capitalized interest in accordance with U.S. GAAP, not regulatory financing cost under AFUDC.

Our provision for depreciation of utility property is computed under the straight-line method in accordance with external engineering studies as approved by regulatory authorities. The weighted average depreciation rate for utility plant in service was approximately 2.8 percent, 2.9 percent and 3.4 percent for the years ended December 31, 2010, 2009 and 2008, respectively, reflecting the approximate average economic life of the property. This includes 2010 weighted average depreciation rates for the following asset classes: 2.7 percent for transmission and distribution, 2.2 percent for utility storage, 4.9 percent for general, and 5.7 percent for intangible and other.

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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 and equity 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 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 the higher utility cost of service. Our composite AFUDC rates were 0.6 percent in 2010, 1.0 percent in 2009 and 3.6 percent in 2008.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand plus highly liquid investment accounts with maturity dates of three months or less. At December 31, 2010, outstanding checks of approximately $1.6 million were included in accounts payable.

Revenue Recognition and Accrued Unbilled Revenues

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 include accruals for gas delivered but not yet billed to customers based on estimates of 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 factors. Accrued unbilled revenues are reversed the following month when actual billings occur. Our accrued unbilled revenues at December 31, 2010 and 2009 were $64.8 million and $71.2 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 refund or surcharge is accrued based on the estimated difference between income taxes paid and income taxes authorized to be collected in rates each tax year.

Non-utility revenues are derived primarily from the gas storage business segment. At Mist, revenues are recognized upon delivery of services to customers. Revenues from our asset optimization partner are recognized over the life of the optimization contract for the guaranteed amount, and recognized as earned for amounts above the guaranteed amount. At Gill Ranch, firm services resulting from short-term and long-term contracts are typically recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized. Hub service fees include interruptible and park and loan services. Interruptible service offers gas storage service to customers under contracts or rate schedules that allow for temporary interruptions to meet the needs of firm service customers. Park and loan service offers customers the option to use gas with a promise to provide gas in the future or store natural gas, usually for short-term durations. Hub service fees are recognized in the period the natural gas moves across our header system. Optimization revenue is recognized according to our profit sharing mechanism, which provides us with 80 percent of the pre-tax income from our independent energy marketing company. See Note 4.

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable consist primarily of amounts due for natural 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 past due account balances 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 information currently 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 utility gas inventories provides for cost recovery in customer rates. Utility gas inventories that are injected into storage are priced into inventory based on actual purchase costs. Utility gas inventories that are withdrawn from inventory storage are charged to cost of gas during the current period at the weighted average cost of inventory.

Gill Ranch gas inventories, excluding cushion gas, consist primarily of gas that we received as fuel-in-kind from storage customers. Gill Ranch gas inventories are valued at the lower of average cost or net realizable value. Cushion gas is recorded at original cost and classified as long-term assets.

Material and supplies inventories are stated at the lower of average cost or net realizable value.

Derivatives

In accordance with accounting for derivatives and hedges, we measure derivatives at fair value and recognize them as either assets or liabilities on the balance sheet. Accounting for derivatives requires that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for derivatives and hedges 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 regulatory accounting principles. Derivative 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. Effective on November 1, 2008, Oregon approved a PGA sharing mechanism under which we are required to select before each gas 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 of gas cost differences compared to PGA prices, respectively. For the PGA years in Oregon beginning November 1, 2010 and 2009, we selected the 90 percent deferral of gas cost differences. For the PGA year in Oregon beginning November 1, 2008, we selected the 80 percent deferral of gas cost differences. In Washington, 100 percent of our gas cost differences are deferred. See Note 13.

Our financial derivatives policies set forth the guidelines for using selected 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 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.

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Fair Value

In accordance with fair value accounting, we use the following fair value hierarchy for determining inputs for our pension plan assets and 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. 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.

Revenue Taxes

We account for revenue-based taxes as a separate cost item collected from customers. 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 tax credits as if each entity filed a separate return. We account for income taxes in accordance with accounting standards for income taxes. Accounting for income taxes 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 10).

Accounting for income taxes 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 of $72.3 million and $76.2 million at December 31, 2010 and 2009, 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 regulatory accounting principles, 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, which reduce income taxes payable, are deferred for financial statement purposes and amortized over the life of the related plant or lease.

Subsequent Events

We monitor significant events occurring after the balance sheet date and prior to the issuance of the financial statements to determine the impacts, if any, of events on the financial statements to be issued. All subsequent events of which we are aware were evaluated through the filing date of this Form 10-K. For subsequent events see Note 16.

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3. Earnings Per Share

Basic earnings per share are computed using the weighted average number of common shares outstanding during each period presented. Diluted earnings per share are computed using the weighted average number of common shares outstanding plus the potential effects of the assumed exercise of stock options and the payment of estimated stock awards from other stock-based compensation plans that are outstanding at the end of each period presented. Diluted earnings per share are calculated as follows:

Thousands, except per share amounts	2010	2009	2008
Net income	$72,667	$75,122	$69,525
Average common shares outstanding - basic	26,589	26,511	26,438
Additional shares for stock-based compensation plans	68	65	156
Average common shares outstanding - diluted	26,657	26,576	26,594
Earnings per share of common stock - basic	$2.73	$2.83	$2.63
Earnings per share of common stock - diluted	$2.73	$2.83	$2.61

For the years ended December 31, 2010, 2009 and 2008, 743 shares, 2,142 shares and 1,248 shares, respectively, were excluded from the calculation of diluted earnings per share because the effect of these additional shares on the net income for these periods would have been antidilutive.

4. 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 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, parts of NWN Energy and its wholly-owned subsidiary NWN Gas Storage, and the non-utility portion of gas storage services related to our Mist underground storage facility in Oregon (Mist). Our "other" segment includes NNG Financial and parts of NWN Energy, including an equity investment in PGH which is developing the Palomar pipeline project (see Other, below).

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 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 in Washington. On an annual basis, residential and commercial customers typically account for 50 to 60 percent of our utility's total volumes delivered and 80 to 90 percent of our utility's margin, while industrial customers account for 40 to 50 percent of volumes and 5 to 15 percent of margin. The remaining 10 percent or less of margin is derived from miscellaneous services, gains or losses from gas cost sharing 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 utility revenues or margins.

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Gas Storage

Our gas storage business segment includes natural gas storage services provided to customers from our two underground natural gas storage facilities, our Gill Ranch gas storage facility, which commenced commercial operations in October 2010, and the non-utility portion of the Mist gas storage facility near Mist, Oregon. In addition to earning revenue from customer storage contracts, we also use an independent energy marketing company to provide asset optimization services for utility and non-utility capacity under a contractual arrangement, the results of which are included in this business segment. For each of the years ended December 31, 2010, 2009 and 2008, this business segment derived a majority of its revenues from asset optimization services and from multi-year gas storage contracts.

Mist Gas Storage Facility. Our total Mist gas storage assets, excluding amounts allocated to our utility, were $58.9 million in 2010 and $58.4 million in 2009. Results for the gas storage segment also include revenues, net of amounts shared with core utility customers, from the optimization of our utility assets when not needed to serve core utility customers. In Oregon, the gas storage segment retains 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.

Gill Ranch Gas Storage Facility. We have a joint project agreement with Pacific Gas and Electric Company (PG&E) to own and operate the Gill Ranch underground natural gas storage facility near Fresno, California. Gill Ranch has a 75 percent undivided ownership interest in the project. The construction of this facility began in January 2010 and a majority of the construction work was complete by October 2010.

Gill Ranch is offering storage services to the California market at market-based rates, subject to CPUC regulation including, but not limited to, service terms and conditions, tariff regulations, and security issuances. As of December 31, 2010 and 2009, total assets at Gill Ranch were $225.2 million and $116.3 million, respectively, and for the years then ended Gill Ranch had a net loss of $2.9 million and $0.3 million, respectively. In 2010, Gill Ranch expenses primarily reflect start-up costs, depreciation, and power costs related to gas injection. Gill Ranch has a 28 year contract for cushion gas for our facility. This $13.5 million liability is included in non-current other liabilities on our balance sheet.

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 NNG Financial. For more on information on Palomar, see Note 12. This segment also includes some operating and non-operating revenues and expenses of the parent company that cannot be allocated to utility operations.

In 2008, we sold our 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 2008.

NNG Financial 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. NNG Financial's total assets were $1.1 million and $1.4 million at December 31, 2010 and 2009, respectively.

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Segment Information Summary

The following table presents summary financial information about the reportable segments for the years ended 2010, 2009 and 2008. Inter-segment transactions are insignificant.

Thousands	Utility	Gas Storage	Other	Total
2010				
Net operating revenues	$346,148	$21,249	$184	$367,581
Depreciation and amortization	62,661	2,463	-	65,124
Income from operations	145,688	11,855	62	157,605
Net income	66,262	6,110	295	72,667
Total assets at December 31, 2010	2,310,388	282,945	23,283	2,616,616
2009				
Net operating revenues	$357,005	$19,738	$144	$376,887
Depreciation and amortization	61,472	1,342	-	62,814
Income from operations	142,228	16,442	46	158,716
Net income	65,960	8,923	239	75,122
Total assets at December 31, 2009	2,205,313	173,648	20,291	2,399,252
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

5. Capital Stock

Common Stock

As of December 31, 2010 and 2009, our common shares authorized were 100,000,000.

As of December 31, 2010, we had reserved for issuances 171,259 shares of common stock under the Employee Stock Purchase Plan (ESPP), 386,188 shares under our Dividend Reinvestment and Direct Stock Purchase Plan and 1,184,060 shares under our Restated Stock Option Plan (Restated SOP).

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 currently have Board authorization through May 2011 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 2010, 2009 or 2008. Since inception in 2000, a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

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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 2010, 2009 and 2008:

	Shares
Balance, December 31, 2007	26,407,348
Sales to employees	19,500
Exercise of stock options - net	74,340
Balance, December 31, 2008	26,501,188
Sales to employees	8,615
Exercise of stock options - net	23,225
Balance, December 31, 2009	26,533,028
Sales to employees	23,659
Exercise of stock options - net	111,525
Balance, December 31, 2010	26,668,212

6. Stock-Based Compensation

We have several stock-based compensation plans, including a Long-Term Incentive Plan (LTIP), a Restated SOP and an ESPP. These plans are designed to promote stock ownership in NW Natural by employees and officers.

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, 2010, 270,204 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, 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, 2010, certain performance-based stock award measures had been achieved for the 2008-10 award period. Accordingly, participants are estimated to receive 8,007 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, 2009 and 2008, we awarded 12,755 and 48,351 shares of common stock net of tax, respectively, for the 2007-09 and 2006-08 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 2010, we expensed $0.2 million related to the 2008-10 performance-based stock award, and on a cumulative basis we accrued a total of $0.7 million related to the 2008-10 performance period. In 2009 and 2008, we expensed $0.5 million for both the 2007-09 and 2006-08 performance-based stock award periods, and on a cumulative basis we accrued a total of $1.5 million and $2.0 million, respectively, related to the 2007-09 and 2006-08 performance periods.

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At December 31, 2010, the aggregate number of performance-based shares granted and outstanding at the threshold, target and maximum levels were as follows:

Year Awarded	Performance Period	Performance Share Awards Outstanding Threshold	Target	Maximum
2009	2009-11	7,410	39,000	78,000
2010	2010-12	7,885	41,500	83,000
	Total	15,295	80,500	161,000

The threshold level estimates future payout assuming the minimum award payable is achieved 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 accounting for stock compensation, 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, 2010 and 2009 was $23.10 and $19.40, respectively. The weighted-average per share grant date fair value of shares vested during the year was $19.38 and granted during the year was $25.58. In 2010, 2009 and 2008 under these LTIP grants we accrued and expensed $0.6 million and $0.5 million, $1.0 million and $0.9 million, and $2.7 million and $2.3 million, respectively.

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 equal to the closing market price on the date of grant and may be exercised for a period up to 10 years and 7 days from the date of grant. Option holders may exchange shares they have owned for at least six months, at the current market price, to purchase shares at the option price.

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 2010	February 2009	September 2008	February 2008	February 2007
Risk-free interest rate	2.3 %	2.0 %	3.0 %	2.8 %	4.7 %
Expected life (in years)	4.7	4.7	4.7	4.7	6.2
Expected market price volatility factor	23.2 %	22.5 %	18.4 %	18.4 %	17.2 %
Expected dividend yield	3.8 %	3.8 %	2.9 %	3.5 %	3.2 %
Forfeiture rate	3.2 %	3.7 %	3.9 %	3.8 %	4.4 %
Weighted average grant date fair value	$6.36	$5.46	$7.05	$5.34	$7.66

The expected life of our grants was calculated based on our actual experience with previously exercised option grants. 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 used 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 future dividend payouts 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 stock option accounting guidance and the retirement vesting provisions of our option agreements.

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Information regarding the Restated SOP activity for the three years ended December 31, 2010 is summarized as follows:

	Option Shares	Price per Share Range	Weighted - Average Exercise Price	Intrinsic Value (In millions)
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
Granted	111,750	41.15	41.15	n/a
Exercised	(23,225)	20.25 - 34.95	30.92	0.3
Balance outstanding, Dec. 31, 2009	484,935	26.30 - 51.09	39.57	2.7
Granted	119,750	44.25	44.25	n/a
Exercised	(111,525)	26.30 - 44.48	39.01	0.9
Forfeited	(2,700)	41.15 - 44.25	43.00	n/a
Balance outstanding, Dec. 31, 2010	490,460	26.30 - $51.09	$40.82	$2.8
Shares available for grant				
Dec. 31, 2008				922,400
Dec. 31, 2009				810,650
Dec. 31, 2010				693,600

In the year ended December 31, 2010, cash of $5.2 million was received for option shares exercised and a $0.1 million related tax benefit was realized. For the 12 months ended December 31, 2010, 2009 and 2008, the total fair value of options that vested was $0.5 million, $0.4 million and $0.3 million, respectively.

The following table summarizes additional information about stock options outstanding and exercisable at December 31, 2010:

	Outstanding		Exercisable			
Range of Exercise Prices	Stock Options	Weighted-Average Remaining Life in Years	Stock Options	Aggregate Intrinsic Value (In millions)	Weighted-Average Exercise Price	Weighted-Average Remaining Life in Years

$26.30 - 51.09	490,460	7.02	239,361	$2.0	$38.30	5.61

As of December 31, 2010, there was $0.9 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2013.

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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.

In accordance with accounting for stock compensation, stock-based compensation expense is recognized as operations and maintenance expense or is capitalized as part of construction overhead. The following table summarizes the financial statement impact of stock-based compensation under our LTIP, Restated SOP and ESPP:

Thousands	2010	2009	2008
Operations and maintenance expense, for stock-based compensation	$1,032	$1,434	$1,598
Income tax benefit	(418)	(559)	(623)
Net stock-based compensation effect on net income	$614	$875	$975
Amounts capitalized for stock-based compensation	$182	$229	$282

7. Cost and Fair Value Basis of Long-Term Debt

Cost of Long-Term Debt

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

The maturities on the long-term debt outstanding for each of the 12-month periods through December 31, 2015 amount to: $10 million in 2011; $40 million in 2012; none in 2013; $60 million in 2014; and $40 million in 2015.

Thousands	2010	2009	2008
Medium-Term Notes			
First Mortgage Bonds:			
4.11 % Series B due 2010	$-	$10,000	$10,000
7.45 % Series B due 2010	-	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
3.95 % Series B due 2014(1)	50,000	50,000	-
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
5.37 % Series B due 2020(2)	75,000	75,000	-
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(3)	19,700	19,700	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
	601,700	636,700	512,000
Less current maturities of long-term debt	10,000	35,000	-
Total long-term debt	$591,700	$601,700	$512,000

(1) Issued in July 2009

(2) Issued in March 2009

(3) In November 2009 one investor in our 6.65 percent secured MTNs due 2027 exercised its right under a one-time put option to redeem $0.3 million of the $20 million outstanding. This one-time put option has now expired, and the remaining $19.7 million remaining principal outstanding is expected to be redeemed at maturity in November 2027.

In March 2009, we issued $75 million of 5.37 percent secured MTNs due February 1, 2020, and in July 2009, we issued another $50 million of secured MTNs with an interest rate of 3.95 percent and a maturity of July 15, 2014. Proceeds from these MTNs were used to fund utility capital expenditures, to redeem utility short-term debt, and to provide utility working capital for general corporate purposes.

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Fair Value of Long-Term Debt

The following table provides an estimate of the fair value of our long-term debt including current maturities of long-term debt, using market prices in effect on the valuation date. Because our debt outstanding does not trade in active markets, we used interest rates for outstanding debt issues that actively trade and have similar credit ratings, terms and remaining maturities to estimate fair value for our long-term debt issues.

	December 31,	
Thousands	2010	2009
Carrying amount	$601,700	$636,700
Estimated fair value	$690,126	$707,755

8. Short-term Debt and Credit Facilities

Our primary source of short-term funds is from the sale of commercial paper and bank loans. 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 and bank loans are 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. Bank loans at Gill Ranch were supported by cash collateral. At December 31, 2010 and 2009, the amounts and average interest rates of commercial paper debt outstanding were $257.4 million at 0.4 percent and $69.8 million at 0.3 percent, respectively.

In March 2009, Gill Ranch entered into a cash collateralized credit facility for up to $40 million. As of December 31, 2009, Gill Ranch had $32.2 million of borrowings outstanding included under short-term debt on the balance sheet, with a corresponding cash collateral amount included under restricted cash – current on the balance sheet. The effective interest rate on Gill Ranch’s credit facility was 0.8 percent. In June 2010, Gill Ranch settled its $40 million bank loan outstanding using proceeds from its cash collateralized account.

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 under this syndicated agreement to May 31, 2013. The syndicated agreement 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 agreement. The syndicated 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 syndicated agreement are due and payable on or before the expiration date, which is May 31, 2013. Additionally, we have three committed bilateral bank lines of credit totaling $50 million in effect as of November 30, 2010. These will expire March 31, 2011. There were no outstanding balances under the syndicated agreement and no letters of credit issued or outstanding at December 31, 2010 and 2009.

The syndicated 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 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, 2010 and 2009.

There were no outstanding balances under the short-term credit agreements as of December 31, 2010. All three lenders under the short-term credit agreements are existing lenders under our syndicated agreement. The short-term credit agreements require us to comply with the terms and conditions of the syndicated agreement and give the lenders under the short-term credit agreements the same rights with respect to the short-term credit agreements that they have under the syndicated agreement. We were in compliance with these covenants at December 31, 2010.

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9. Pension and Other Postretirement Benefits

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 postretirement employee benefit plans. We also have a qualified defined contribution plan (Retirement K Savings Plan) for all eligible employees. Only the two qualified defined benefit pension plans and Retirement K Savings Plan have plan assets, which are held in a qualified trust to fund retirement benefits. Effective January 1, 2007 and 2010, the qualified defined benefit retirement plans and postretirement benefits for non-union employees and for union employees, respectively, were closed to new participants. These plans were not available to employees of our NWN Gas Storage subsidiary. Instead, non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and our NWN Gas Storage employees are provided an enhanced Retirement K Savings Plan benefit. Also, effective January 1, 2007, the postretirement Welfare Benefit Plan for Non-Bargaining Unit Employees was closed to new participants after December 31, 2006.

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 for the years ended December 31, 2010, 2009, and 2008, and a summary of the funded status and amounts recognized in the consolidated balance sheets using measurement dates as of December 31, 2010, 2009 and 2008:

	Postretirement Benefit Plans					
	Pension Benefits			Other Benefits		
Thousands	2010	2009	2008	2010	2009	2008
Reconciliation of change in benefit obligation:						
Obligation at January 1	$307,991	$281,127	$260,561	$24,741	$23,863	$22,186
Service cost	6,688	6,402	6,141	588	522	521
Interest cost	18,029	17,948	17,373	1,436	1,568	1,403
Net actuarial (gain) or loss	762	9,319	4,291	670	(883)	173
Benefits paid	(18,645)	(17,149)	(16,247)	(1,476)	(1,428)	(1,259)
Plan amendments	-	(3,921)	5	-	-	-
Change in assumptions	24,513	14,265	9,146	1,717	1,099	839
Liability transfer	-	-	(143)	-	-	-
Obligation at December 31	$339,338	$307,991	$281,127	$27,676	$24,741	$23,863
Reconciliation of change in plan assets:						
Fair value of plan assets at January 1	$201,312	$163,115	$241,418	$-	$-	$-
Actual return on plan assets	24,651	28,641	(63,267)	-	-	-
Employer contributions	11,696	26,705	1,211	1,476	1,428	1,259
Benefits paid	(18,645)	(17,149)	(16,247)	(1,476)	(1,428)	(1,259)
Fair value of plan assets at December 31	$219,014	$201,312	$163,115	$-	$-	$-
Funded status at December 31	$(120,324)	$(106,679)	$(118,012)	$(27,676)	$(24,741)	$(23,863)

Our qualified defined benefit pension plans had an aggregate projected benefit obligation of $ 314.5 million, $285.2 million and $261.5 million at December 31, 2010, 2009, and 2008, respectively, and the fair value of plan assets was $

219.0 million, $201.3 million and $163.1 million, respectively. Changes in valuation assumptions impact our projected benefit obligations. Benefit obligations at December 31, 2010 increased $17.9 million due to a decrease in our discount rate assumptions and increased by $6.5 million due to changes in other assumptions. The projected benefit obligations at December 31, 2009 increased $19.1 million over the prior year due to a decrease in our discount rate assumptions and increased by $4.2 million due to changes in other assumptions.

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The following table provides amounts amortized from accumulated other comprehensive income (AOCI) or regulatory assets to net periodic benefit cost during 2010, 2009, and 2008:

	Regulatory Asset Amortization						AOCI Amortization		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
Thousands	2010	2009	2008	2010	2009	2008	2010	2009	2008
Net periodic benefit costs:									
Actuarial loss	$6,740	$6,189	$-	$131	$17	$-	$707	$449	$398
Prior service cost	230	1,260	1,290	197	197	197	(43)	(37)	(37)
Transition obligation	-	-	-	411	411	411	-	-	-
Total	$6,970	$7,449	$1,290	$739	$625	$608	$664	$412	$361

In 2011, an estimated $11.0 million will be amortized from regulatory assets to net periodic benefit costs, consisting of $10.2 million of actuarial losses, $0.4 million of prior service cost and $0.4 million transition obligation, and $0.9 million will be amortized to AOCI, consisting of $0.8 million of actuarial losses and $0.1 million of prior service cost.

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 S&P or Aa3 or higher by Moody's). The discount rate curve was then applied to match the estimated cash flows in each plan to reflect the timing and amount of expected future benefit payments for these plans.

The assumption for 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 with the assistance of an investment consultant. 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 include cash and short-term investments, fixed income, common stock and convertible securities, absolute and real return strategies, real estate and investments in our common stock. Plan assets may be invested in separately managed accounts or in commingled or mutual funds. Investment re-balancing takes 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, diversified asset allocation and active portfolio management by professional investment managers. The Retirement Trust Fund is not currently invested in any NW Natural securities.

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Our pension plan asset allocation at December 31, 2010 and 2009, 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, 2010		2009		Target Allocation		Expected Long-term Rate of Return	
US Large Cap Equity	17.0	%	17.5	%	18	%	8.25	%
US Small/Mid Cap Equity	12.7	%	13.8	%	12	%	9.25	%
Non-US Equity	17.9	%	19.4	%	18	%	8.85	%
Emerging Markets	5.2	%	0.5	%	5	%	10.50	%
Fixed Income	16.6	%	18.2	%	17	%	5.25	%
Real Estate	6.8	%	6.5	%	8	%	7.00	%
Absolute Return Strategy	14.8	%	15.0	%	15	%	8.00	%
Real Return Strategy	7.1	%	6.8	%	7	%	7.00	%
Cash and cash equivalents	1.9	%	2.3	%	0	%	-	
Weighted Average							8.25	%

Our non-qualified supplemental defined benefit pension benefit obligations were $ 24.9 million, $22.8 million and $19.6 million at December 31, 2010, 2009 and 2008, 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 these are unfunded plans with no plan assets due to their nature as non-qualified plans, we indirectly fund a portion of 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 $ 27.7 million, $24.7 million and $23.9 million at December 31, 2010, 2009 and 2008, 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 or less from the year in which they occur, thereby reducing year-to-year net periodic benefit cost volatility.

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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, 2010, 2009 and 2008 and the assumptions used in measuring these costs and benefit obligations:

	Pension Benefits			Other Postretirement Benefits		
Thousands	2010	2009	2008	2010	2009	2008
Service cost	$6,688	$6,402	$6,141	$588	$522	$521
Interest cost	18,029	17,948	17,373	1,436	1,568	1,403
Expected return on plan assets	(18,207)	(15,696)	(19,087)	-	-	-
Amortization of transition obligations	-	-	19	411	411	411
Amortization of prior service costs	187	1,223	1,253	197	197	197
Amortization of net actuarial loss	7,447	6,810	385	131	-	-
Net periodic benefit cost	$14,144	$16,687	$6,084	$2,763	$2,698	$2,532
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	6.01 %	6.60 %	6.79 %	5.78 %	7.12 %	6.56 %
Rate of increase in compensation	3.25-5.0 %	3.25-5.0 %	3.5-5.0 %	n/a	n/a	n/a
Expected long-term rate of return	8.25 %	8.25 %	8.25 %	n/a	n/a	n/a
Assumptions for funded status:						
Weighted-average discount rate	5.49 %	6.01 %	6.60 %	5.16 %	5.78 %	7.12 %
Rate of increase in compensation	3.25-5.0 %	3.25-5.0 %	3.5-5.0 %	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 health care cost trend rates used in measuring other postretirement benefits as of December 31, 2010 were 8.5 percent for medical and 10.5 percent for prescription drugs. Medical costs and prescription drugs are assumed to decrease gradually each year to a rate of 5.0 percent by 2021.

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 retirement benefit costs and benefit obligations to future changes in certain actuarial assumptions:

Thousands, except percent	Change in Assumption	Impact on 2010 Retirement Benefit Costs	Impact on Retirement Benefit Obligations at Dec. 31, 2010

Discount rate:	(0.25 %)			
Qualified defined benefit plans		$ 850		$ 9,623
Non-qualified plans		8		42
Other postretirement benefits		42		647
Expected long-term return on plan assets:	(0.25 %)			
Qualified defined benefit plans		552		N/A

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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 net periodic postretirement health care benefit cost	$64	$(57)
Effect on the accumulated postretirement benefit obligation	$688	$(622)

The impact of a change in retirement benefit 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.

The following table provides information regarding employer contributions and benefit payments for the two qualified pension plans, non-qualified pension plans and other postretirement benefit plans for the years ended December 31, 2010 and 2009, and estimated future contributions and payments:

Thousands Employer Contributions	Pension Benefits	Other Benefits
2009	$27,137	$1,428
2010	12,088	1,476
2011 (estimated)	23,668	2,109
Benefit Payments		
2008	16,247	1,259
2009	17,149	1,428
2010	18,645	1,476
Estimated Future Payments		
2011	18,632	2,109
2012	19,120	2,078
2013	19,396	2,096
2014	19,962	2,169
2015	20,560	2,159
2016-2020	117,507	11,226

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, as measured under the Act, of 94 percent in 2009 and 96 percent in 2010. Our qualified defined benefit pension plans are currently underfunded by $95.4 million at December 31, 2010, and we expect to make contributions during 2011 of approximately $22 million.

The Retirement K Savings Plan provided to our employees is a qualified defined contribution plan under Internal Revenue Code Section 401(k). The supplemental deferred compensation plans for eligible officers and senior managers are non-qualified plans. These plans are designed to enhance the retirement savings of employees and to assist them in strengthening their financial security by providing an incentive to save and invest regularly. Our contributions to these plans totaled $2.1 million in 2010, 2009 and 2008. The Retirement K Savings Plan 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 to the Western States Plan amounted to $0.4 million in 2010, 2009 and 2008.

Fair Value

Following is a description of the valuation methodologies used for assets measured at fair value. In cases where the pension plan is invested through a collective trust fund or mutual fund, our custodian uses the fund's market value. The custodian also provides the market values for investments directly owned.

U.S. large cap equity: These are level 1 assets valued at the closing price reported on the active market on which the individual security is traded. This asset class includes investments primarily in U.S. common stocks.

U.S. small/mid cap equity: These are level 2 assets valued based on information provided by the plan's investment custodians. The financial statements of the commingled fund are audited annually by independent accountants. Values for such funds are stated at estimated fair values, which have been determined based on the unit values of the funds. Unit values are determined by the bank sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation date. This asset class includes investments primarily in U.S. common stocks.

Non-U.S. equity: These are level 1 and 2 assets. Level 1 assets are valued at the closing price reported on the active market on which the individual security is traded. Level 2 assets are valued based on information provided by the plan's investment custodians. The financial statements of the commingled fund are audited annually by independent accountants. Values for such funds are stated at estimated fair values, which have been determined based on the unit values of the funds. Unit values are determined by the bank sponsoring such funds by dividing the fund's net assets at fair value by its units outstanding at the valuation date. This asset class includes investments primarily in foreign equity common stocks.

Emerging market equity: These are level 1 assets valued at the net asset value of the shares held by the plan at the valuation date. This asset class includes investments primarily in common stocks in emerging markets.

Fixed income: These are level 1 assets valued at the net asset value of the shares held by the plan at the valuation date. This asset class includes investments primarily in investment grade debt and fixed income securities.

Real estate funds: These are level 3 assets valued based on the interest held by the plan, for which fair values of the underlying investments are subject to appraisal as directed by the funds' management. This asset class includes a real estate fund that invests directly in real estate. The underlying properties held in the funds are appraised utilizing the following approaches: the cost approach (the current cost of replacing the real estate less deterioration and functional and economic obsolescence); the income approach (the ability of the underlying properties to generate net rental income); and the comparable sales approach (recent sales of comparable real estate in the same market). The plan's ability to redeem these investments is subject to certain restrictions and cash availability.

Absolute return strategy: These are level 2 assets valued based on information provided by the plan's investment custodians. The financial statements of the partnerships are audited annually by independent accountants, with the value of the underlying investments based on the estimated fair value of the various holdings in the portfolio as reported in the financial statements at net asset value. This asset class includes a hedge fund of funds. Our investment normally provides for a quarterly distribution subject to 95 days advance notice of withdrawal. Currently there are no restrictions on withdrawal requests, and as of December 31, 2010 we have not submitted a withdrawal request.

Real return strategy: These are level 1 assets valued at the net asset value of the shares held by the plan at the valuation date. This asset class includes an investment in a broad range of assets and strategies primarily including fixed income and equity securities, along with commodities.

Cash and cash equivalents: These are level 2 assets valued at the net asset value of the shares held by the plan at the valuation date. This asset class primarily includes a money market mutual fund.

The preceding valuation methods may produce a fair value calculation that is not indicative of net realizable value or reflective of future fair values. Furthermore, although we believe these valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

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Investment securities are exposed to various financial risks including interest rate, market and credit risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the values of our investment securities will occur in the near term and that such changes could materially affect our investment account balances and the amounts reported as plan assets available for benefits payments.

The following table presents the fair value of plan assets, including outstanding receivables and liabilities, of the Retirement Trust Fund as of December 31, 2010 and 2009:

	December 31, 2010			
Investments, in thousands	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$ 37,231	$ -	$ -	$ 37,231
U.S. small/mid cap equity	-	27,864	-	27,864
Non-U.S. equity	24,630	14,549	-	39,179
Emerging markets equity	11,476	-	-	11,476
Fixed income	36,429	-	-	36,429
Real estate	-	-	14,721	14,721
Absolute return strategy	-	32,378	-	32,378
Real return strategy	15,452	-	-	15,452
Cash and cash equivalents	-	3,629	-	3,629
Total investments	$ 125,218	$ 78,420	$ 14,721	$ 218,359

	December 31, 2009			
Investments, in thousands	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$ 35,266	$ -	$ -	$ 35,266
U.S. small/mid cap equity	-	27,953	-	27,953
Non-U.S. equity	25,395	13,456	-	38,851
Emerging markets equity	1,021	-	-	1,021
Fixed income	36,682	-	-	36,682
Real estate	-	-	12,936	12,936
Absolute return strategy	-	30,097	-	30,097
Real return strategy	13,592	-	-	13,592
Cash and cash equivalents	-	4,614	-	4,614
Total investments	$ 111,956	$ 76,120	$ 12,936	$ 201,012

	December 31,	
Receivables	2010	2009
Accrued interest and dividend income	$ 249	$ 200
Due from broker for securities sold	448	400
Total receivables	$ 697	$ 600
Liabilities		
Due to broker for securities purchased	$ 42	$ 300
Total investment in retirement trust	$ 219,014	$ 201,312

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Level 3 Investments

The following table presents the beginning balance, activity and ending balance of Level 3 investments that have their fair values established using significant unobservable inputs as of December 31, 2010:

Thousands	Level 3 Assets Real estate Funds
January 1, 2010 balance	$12,936
Total gains or (losses)	
Included in earnings (or changes in net assets)	1,785
Purchases, sales, issuances and settlements	
December 31, 2010 balance	$14,721

10. Income Tax

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	2010	2009	2008
Income taxes at federal statutory rate	$42,745	$42,627	$38,571
Increase (decrease):			
Current state income tax, net of federal tax benefit	5,803	5,568	4,100
Amortization of investment and energy tax credits	(525)	(593)	(646)
Differences required to be flowed-through by regulatory commissions	1,647	(116)	(704)
Gains on company and trust-owned life insurance	(715)	(1,195)	(767)
Other - net	507	380	124
Total provision for income taxes	$49,462	$46,671	$40,678
Federal statutory tax rate	35.0%	35.0%	35.0%
Increase (decrease):			
Current state income tax, net of federal tax benefit	4.8%	4.6%	3.7%
Amortization of investment and energy tax credits	-0.4%	-0.5%	-0.6%
Differences required to be flowed-through by regulatory commissions	1.3%	-0.1%	-0.6%
Gains on company and trust-owned life insurance	-0.6%	-1.0%	-0.7%
Other - net	0.4%	0.3%	0.1%
Effective tax rate	40.5%	38.3%	36.9%

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The provision (benefit) for current and deferred income taxes consists of the following:

Thousands	2010	2009	2008
Current			
Federal	$(28,592)	$6,221	$(7,970)
State	1,441	2,300	(437)
	(27,151)	8,521	(8,407)
Deferred			
Federal	69,159	31,937	42,862
State	7,454	6,213	6,223
	76,613	38,150	49,085
Total provision for income taxes	$49,462	$46,671	$40,678
Total income taxes paid	$22,600	$10,000	$12,300

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

Thousands	2010	2009	2008
Regulated utility:			
Current	$(1,464)	$871	$(13,034)
Deferred	47,741	40,829	48,790
Deferred investment and energy tax credits	(525)	(593)	(646)
	45,752	41,107	35,110
Non-utility business segments:			
Current	(25,687)	7,650	4,627
Deferred	29,397	(2,086)	941
	3,710	5,564	5,568
Total provision for income taxes	$49,462	$46,671	$40,678

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

Thousands	2010	2009
Deferred tax liabilities:		
Plant and property	$255,471	$231,768
Regulatory adjustment for income taxes paid	5,272	2,169
Regulatory income tax assets	68,822	72,721
Regulatory liabilities	23,159	13,506
Non-regulated deferred tax liabilities	34,544	-
Total	$387,268	$320,164
Deferred tax assets:		
Regulatory assets	(1,402)	(14,436)
Unfunded pension and postretirement obligations	(4,342)	(3,925)
Non-regulated deferred tax assets	(772)	(2,860)
Alternative minimum tax credit carryforward	(1,702)	-
Loss and credit carryforwards	(7,071)	-
Total	(15,289)	(21,221)
Deferred income tax liabilities - net	371,979	298,943
Deferred investment tax credits	1,430	1,955
Deferred income taxes and investment tax credits	$373,409	$300,898

We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2010.

The following is a reconciliation of the change in our deferred tax balance for the year ended December 31, 2010:

Thousands	2010
Deferred tax expense, above, including investment tax credit	$77,138
Decrease in differences required to be flowed-through	(3,899)
Increase in minimum pension liability included in AOCI	(417)
Decrease in deferred taxes associated with asset held for sale	214
Decrease in deferred investment tax credits	(525)
Change in deferred income tax accounts	$72,511

We calculate our deferred tax assets and liabilities according to accounting guidance on income taxes, whereby deferred income taxes are generally determined based on the difference between the financial statement and tax bases 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.

In September 2010, Congress passed the Unemployment Insurance, Reauthorization and Job Creation Act of 2010 (the 2010 Act) and the legislation was signed into law by President Obama. The Act extends for one additional year the temporary 50 percent bonus depreciation first enacted in the Economic Stimulus Act of 2008 (the 2008 Act) and subsequently renewed in the American Recovery and Reinvestment Act of 2009. Under the 2010 Act, an additional temporary first-year tax deduction for depreciation equal to 100 percent of the adjusted basis of qualified property may be deducted in the year the property is placed in service. The 100 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. As a result of this extension, we will recognize an increase in our cash flow by reducing our current tax liability for the 2010 tax year. Any deductions in excess of income for federal income tax purposes will be carried back to the 2009 tax year or carried forward to the 2011 tax year. We estimate this extension will generate cash flow of between $40 million to $45 million in federal income taxes.

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For the year ended December 31, 2010, we reported an estimated net operating loss (NOL) for federal income tax purposes of $94.4 million, primarily due to the effects of accelerated tax depreciation provided by the 2010 Act. The federal NOL will be carried back to 2009 and partially utilized for a refund of taxes paid in prior years. The remaining NOL of approximately $20.2 million will be carried forward to reduce current taxes paid in the 2011 tax year. We anticipate that we will be able to use all loss carryforwards in future years. The 2010 federal NOL would expire in 2031 if not used in earlier years.

In December 2008, we filed an application with the Internal Revenue Service (IRS) requesting a change in our tax accounting method to expense routine repair and maintenance costs for gas pipelines that are currently being capitalized and depreciated for book purposes. The IRS consented to our request in August 2009, and we recognized a tax deduction of approximately $59 million on our 2008 tax return as a result of this method change, which resulted in a federal refund of approximately $21 million during the fourth quarter of 2009.

For the year ended December 31, 2008, we reported an 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 2008 Act. As a result of the change in our tax accounting method for repair and maintenance costs discussed above as well as our increased pension contribution, our NOL for federal and Oregon income tax purposes was $89.0 million and $87.2 million on our 2008 federal and Oregon tax returns, respectively. The federal NOL was carried back to 2006 and fully utilized for a refund of taxes paid in prior years, while the Oregon NOL was carried forward to 2009 and fully utilized reducing current Oregon taxes paid for the 2009 tax year.

Uncertain tax positions are accounted for in accordance with accounting standards that require management's assessment of the expected treatment of a tax position taken in a filed tax return, or planned to be taken in a future tax return, that has not been reflected in measuring income tax expense for financial reporting purposes. Until such positions are sustained by the taxing authorities, we would not recognize the tax benefits resulting from such positions and would report the tax effect as a liability in the Company's consolidated balance sheet. As of December 31, 2010, we had no uncertain tax positions.

An IRS examination of the 2006 through 2008 consolidated federal income tax returns commenced during the fourth quarter of 2009. The IRS completed its examination of the 2002 through 2004 audit cycle in the second quarter of 2006. Completion of the 2006 through 2008 federal income tax return examination is expected during the first quarter of 2011.

The Oregon Department of Revenue (ODOR) is currently examining our 2006 through 2008 consolidated Oregon income tax returns. Completion of this examination is expected during the first quarter of 2011.

Interest and penalties related to any future income tax deficiencies will be recorded within income tax expense in the consolidated statements of income.

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11. Property, Plant and Equipment

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

	December 31,	
Thousands, except percentages	2010	2009
Utility plant in service	$2,247,952	$2,188,176
Utility construction work in progress	29,324	27,936
Less accumulated depreciation	710,214	682,060
Utility plant-net	1,567,062	1,534,052
Non-utility plant in service	290,038	66,084
Non-utility construction work in progress	9,088	80,538
Less accumulated depreciation	12,025	10,540
Non-utility plant-net	$287,101	$136,082
Total property plant and equipment	$1,854,163	$1,670,134

The weighted average depreciation rate for utility assets was 2.8 percent in 2010 and 2.9 percent in 2009. The weighted average depreciation rate for non-utility assets was 2.5 percent in 2010 and 2.2 percent in 2009.

Accumulated depreciation does not include the accumulated provision for asset removal costs of $252.9 million and $238.8 million at December 31, 2010 and 2009, respectively. These accrued asset removal costs are reflected on the balance sheets as regulatory liabilities (see Note 2, "Plant and Property and Accrued Asset Removal Costs").

The OPUC and WUTC approved our filed depreciation study and our request to change the amortization of our regulatory tax asset account balance on pre-1981 plant. These approvals specifically authorized the implementation of new depreciation rates in Oregon and Washington, with a corresponding decrease to customer billing rates effective January 1, 2009. The new regulatory tax amortization schedule on pre-1981 assets, with a corresponding increase to customer rates, became effective January 1, 2009 in Washington and November 1, 2009 in Oregon. The implementation of the new rates decreases depreciation expense and increases income tax expense, both of which are offset on an annualized basis by a corresponding change in utility operating revenues. FERC also approved the application of these new depreciation rates for our interstate gas storage assets in May 2009, and the new rates were made effective as of January 1, 2009. Due to the depreciation rate decreases, total depreciation and amortization expense in 2009 decreased by $9.3 million, or 13 percent. In 2010 asset additions have caused an increase in total depreciation and amortization expense of $2.3 million, or 3.7 percent.

12. Investments

Our other long-term investments include financial investments in life insurance policies, which are accounted for at fair value, and equity investments in certain partnerships and limited liability companies, which are accounted for under the equity or cost methods. The following table summarizes our long-term investments at December 31:

Thousands	2010	2009
Life insurance investments	$51,090	$49,327
Note receivable	12	609
Investments in gas pipeline joint ventures	15,742	15,154
Other	2,250	2,275

Total other investments	$69,094	$67,365

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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.

Investments in Gas Pipeline Joint Ventures. We have two investments in gas pipeline joint ventures. Our primary investment is in PGH, owned 50 percent by us and 50 percent by Gas Transmission Northwest Corporation, an indirect wholly-owned subsidiary of TransCanada Corporation. Our other gas pipeline joint venture investment is a 10 percent undivided interest that is not material to our consolidated assets or net income. PGH plans to develop a natural gas transmission pipeline in Oregon to serve our utility as well as the growing natural gas markets in Oregon and other parts of the Pacific Northwest, through its wholly-owned subsidiary Palomar. Palomar is a development stage entity. As of December 31, 2010 and 2009 our investment in PGH was $14.8 million and $14.1 million, respectively, primarily related to planning and permitting. The increase in our equity investment balance over the last 12 months is from an income allocation based on our 50 percent ownership interest. We did not make any equity contributions during 2010.

Variable Interest Entities. PGH is a variable interest entity. As of December 31, 2010, we updated our VIE analysis and determined that we are not the primary beneficiary of PGH's activities as defined by the authoritative guidance related to consolidations (see Note 2). Therefore, we account for our investment in PGH and the Palomar project under the equity method, which is included in other investments on our balance sheet. Our maximum loss exposure related to PGH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50 percent owner.

PGH Impairment Analysis. In May 2010, we learned that the company proposing to build an LNG terminal on the Columbia River had suspended its operations and filed for bankruptcy. This company previously entered into a precedent agreement with Palomar for a majority of the transmission capacity on the proposed pipeline. As of December 31, 2010, Palomar had incurred a total $45.6 million of capital costs, including AFUDC, toward the development of the pipeline (both east and west segments), and it had collected $15.8 million from a letter of credit which supported the bankrupt shipper's obligations under a prior precedent agreement. Palomar also received certain assets out of the bankrupt company's liquidation.

We performed an impairment analysis of our total equity investment as of December 31, 2010 and determined that no impairment write-down is needed because the fair value of the expected development of this pipeline exceeds our total equity investment. If, however, we learn that the project is not viable, we could be required to recognize an impairment of up to approximately $14 million based on the amount of our equity investment as of December 31, 2010 net of cash and working capital at Palomar. We will continue to monitor and update our impairment analysis as needed.

13. Derivative Instruments

We enter into swap, option and combinations of option contracts for the purpose of hedging natural gas which qualify as non-trading derivative instruments under accounting rules for derivative instruments and hedging activities. We primarily use these derivative financial instruments to manage commodity prices related to our natural gas purchase requirements.

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 gas supply contracts. Derivatives entered into prudently for future gas years prior to our annual PGA filing receive regulatory deferred accounting treatment. Derivative contracts entered into after the annual PGA rate was set on November 1, 2010 that are for the current gas contract year are subject to our PGA incentive sharing mechanism, which provides for 90 percent of the changes in fair value to be deferred as regulatory assets or liabilities and the remaining 10 percent to be recorded to the income statement for contracts not qualifying for cash flow hedge accounting and to other comprehensive income for contracts qualifying for cash flow hedge accounting.

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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 because they 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 accounting for derivatives and hedges. The mark-to-market adjustment at December 31, 2010 was an unrealized gain of $0.1 million. This unrealized gain is subject to regulatory deferral and, as such, was recorded as a derivative instrument, which is offset by recording a corresponding amount to a regulatory liability account.

The unrealized mark-to-market value at December 31, 2010 for all derivative contracts outstanding was a net loss of $52.6 million consisting of the following: a $52.7 million unrealized loss on natural gas commodity hedge and derivative contracts, and a $0.1 million unrealized gain 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, 2010, 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 dollar offset method under accounting for derivatives and hedges to determine the hedge effectiveness of derivative contracts. The effectiveness test applied to financial derivatives is dependent on the type of derivative and its use. All derivatives were effective as of December 31, 2010.

Most of our commodity hedging for the upcoming gas year is completed prior to the start of each gas year, and these hedge prices are included in our annual PGA filing. We typically hedge approximately 75 percent of our anticipated year-round sales volumes based on normal weather. We entered the 2010-11 gas year (November 1, 2010 – October 31, 2011) hedged at a targeted level of approximately 77 percent, including 62 percent financially hedged and 15 percent physically hedged through gas storage volumes.

At December 31, 2010 we were hedged with financial contracts for the upcoming gas year at approximately 45 percent, based on anticipated sales volumes. Of the amount hedged for the 2011-12 gas year at December 31, 2010, we were hedged approximately 30 percent with financial contracts, and at 15 percent attributable to storage.

The following table discloses the balance sheet presentation of our derivative instruments as of December 31, 2010 and 2009:

	Fair Value of Derivative Instruments			
	2010		2009	
Thousands	Current	Non-Current	Current	Non-Current
Assets:(1)				
Natural gas commodity	$ 2,154	$ 628	$ 6,214	$ 843
Foreign exchange	91	-	290	-
Total	$ 2,245	$ 628	$ 6,504	$ 843
Liabilities:(2)				
Natural gas commodity	$ 38,437	$ 17,022	$ 19,643	$ 3,193
Total	$ 38,437	$ 17,022	$ 19,643	$ 3,193

(1) Unrealized fair value gains are classified under current- or non-current assets as derivative instruments.

(2) Unrealized fair value losses are classified under current- or non-current liabilities as derivative instruments.

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The following table discloses the income statement presentation for the unrealized gains and losses from our derivative instruments for the years ended December 31, 2010 and 2009. All of our currently outstanding derivative instruments are related to regulated utility operations as illustrated by the derivative gains and losses being deferred to balance sheet accounts in accordance with regulatory accounting.

	2010		2009	
Thousands	Natural gas commodity(1)	Foreign exchange (2)	Natural gas commodity(1)	Foreign exchange (2)
Cost of sales	$ (52,677)	$ -	$ (15,779)	$ -
Other comprehensive income (loss)	-	91	-	290
Less:				
Amounts deferred to regulatory accounts on balance sheet	52,677	(91)	15,779	(290)
Total impact on earnings	$ -	$ -	$ -	$ -

(1) Unrealized gain (loss) from natural gas commodity hedge contracts is recorded in cost of sales and reclassified to regulatory deferral accounts on the balance sheet.

(2) Unrealized gain (loss) from foreign exchange forward purchase contracts is recorded in other comprehensive income, and reclassified to regulatory deferral accounts on the balance sheet.

Our derivative instrument liabilities exclude the netting of collateral. We had no collateral posted with our counterparties as of December 31, 2010 or 2009. We attempt to minimize the potential exposure to collateral calls by our counterparties to manage our liquidity risk. Based on our current credit ratings, most counterparties allow us credit limits ranging from $25 million to $50 million before collateral postings are required. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We also could be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change. Based upon current contracts outstanding, which reflect unrealized losses of $52.7 million at December 31, 2010, we have estimated the projected collateral demands, with and without potential adequate assurance calls, using current gas prices and various downgrade credit rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
Thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$ -	$-	$1,988	$6,988	$27,300
Without Adequate Assurance Calls	$ -	$-	$1,988	$6,988	$23,527

As of December 31, 2010 and 2009, we realized net losses of $61.0 million and $187.9 million, respectively, from the settlement of natural gas hedge contracts at maturity, which were recorded as increases to the cost of gas. The currency exchange rate in all foreign currency forward purchase contracts is included in our purchased cost of gas at settlement; therefore, no gain or loss is recorded from the settlement of those contracts. We settled our $50 million interest rate swap in March 2009, concurrent with our issuance of the underlying long-term debt, and realized a $10.1 million effective hedge loss which is being amortized to interest expense over the term of the debt.

We are exposed to derivative credit risk primarily through securing pay-fixed natural gas commodity swaps to hedge the risk of price increases for our natural gas purchases on behalf of customers. We utilize master netting arrangements through International Swaps and Derivatives Association contracts to minimize this risk along with collateral support agreements with counterparties based on their credit ratings. In certain cases we require guarantees or letters of credit from counterparties in order for them to meet our minimum credit requirement standards.

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Our financial derivatives policy requires counterparties to have a certain investment-grade credit rating at the time the derivative instrument is entered into, and the policy specifies limits on the contract amount and duration based on each counterparty's credit rating. We do not speculate on derivatives; instead we utilize derivatives to hedge our exposure above risk tolerance limits. Any increase in market risk created by the use of derivatives should be offset by the exposures they modify.

We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require other forms of credit assurance, such as letters of credit, cash collateral or guarantees as circumstances warrant. Our ongoing assessment of counterparty credit risk includes consideration of credit ratings, credit default swap spreads, bond market credit spreads, financial condition, government actions and market news. We utilize a Monte-Carlo simulation model to estimate the change in credit and liquidity risk from the volatility of natural gas prices. We use the results of the model to establish earnings at-risk trading limits. Our credit risk for all outstanding derivatives at December 31, 2010 currently does not extend beyond October 2013.

We could become materially exposed to credit risk with one or more of our counterparties if natural gas prices experience a significant increase. If a counterparty were to become insolvent or fail to perform on its obligations, we could suffer a material loss, but we would expect such loss to be eligible for regulatory deferral and rate recovery, subject to prudency review. All of our existing counterparties currently have investment-grade credit ratings.

Fair Value

In accordance with fair value accounting, 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 non-performance 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, 2010. We also did not have any transfers between level 1 or level 2 during the year ended December 31, 2010 and 2009.

The following table provides the fair value hierarchy of our net derivative instruments as of December 31, 2010 and 2009:

Thousands	Description of Derivative Inputs	2010	2009
Level 1	Quoted prices in active markets	$-	$-
Level 2	Significant other observable inputs	(52,586)	(15,489)
Level 3	Significant unobservable inputs	-	-
		$(52,586)	$(15,489)

14. Leases

We lease land, buildings and equipment under agreements that expire in various years through 2095. Rental expense under operating leases was $5.1 million, $5.3 million and $4.7 million for the years ended December 31, 2010, 2009 and 2008, respectively. The table below reflects the future minimum lease payments due under non-cancelable leases at December 31, 2010. Such payments total $52.7 million for operating leases. The net present value of payments on capital leases less imputed interest was $1.0 million. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities, vehicles and computer equipment.

Later

Thousands	2011	2012	2013	2014	2015	years
Operating leases	$4,984	$4,937	$4,909	$5,152	$5,034	$28,169
Capital leases	482	330	178	9	-	-
Minimum lease payments	$5,466	$5,267	$5,087	$5,161	$5,034	$28,169

15. Commitments and Contingencies

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, 2010:

Thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2011	$111,514	$87,046	$3,464
2012	19,310	56,610	-
2013	13,684	48,953	-
2014	11,404	25,059	-
2015	-	17,853	-
Thereafter	-	253,254	-
Total	155,912	488,775	3,464
Less: Amount representing interest	1,151	129,793	5
Total at present value	$154,761	$358,982	$3,459

Our total payments for fixed charges under capacity purchase agreements in 2010, 2009 and 2008 were $91.4 million, $84.6 million and $85.7 million, respectively. Included in the amounts were reductions for capacity release sales of $4.2 million for 2010, $4.2 million for 2009 and $5.0 million for 2008. 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.

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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 and evaluate 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 site investigations, in some cases we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the potential loss and the fact that the high end of the range cannot be reasonably estimated.

We regularly review our environmental 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 and scope of the effort. Many of these steps are dependent upon the approval and direction of federal and state environmental regulators. The policies, determinations and directions of the regulators may develop and change over time and different regulators may take different positions on the various steps, creating further uncertainty as to the timing and scope of remediation activities. 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 and scope 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.

We estimate the range of loss for 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 an estimate within this range of possible losses that is more likely than other cost estimates, we record the liability at the lower end of this range. It is likely that changes in these estimates and ranges 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 (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 Remediation Investigation Report and submitted it to the ODEQ for review. We also submitted a Focused Feasibility Study (FFS) for the groundwater source control portion of the Gasco site, which ODEQ conditionally approved in March 2008, subject to the submission of additional information. We provided that information to ODEQ and are now working with the agency on the final design for the source control system. Based on the information currently available for groundwater source control at the Gasco site and our current assumptions regarding remediation, we have estimated a range of liability between $11 million and $30 million, for which we have recorded an accrued liability of $11.4 million at December 31, 2010. The range of liability will be reassessed when ODEQ makes a final source control design decision. In addition to groundwater source control, we signed a joint Order on Consent with the Environmental Protection Agency (EPA), which requires the design of remedial action for sediments from the Gasco site. This design project is underway. We also have other investigation and clean-up work, including work on the uplands portion of the Gasco site, that we expect to be required. For the sediments project and other work, we have recorded an additional accrued liability of $38.9 million, which reflects the low end of the range of potential liability. We have accrued at the low end of the range of potential liability for the sediments project and other environmental work at the Gasco site 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 conducting an investigation of manufactured gas plant wastes on the uplands at this site for the ODEQ. The liability accrued at December 31, 2010 for the Siltronic site is $0.9 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.

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Portland Harbor site. In 1998, the ODEQ and the EPA completed a study of sediments in a 5.5-mile segment of the Willamette River (Portland Harbor) that includes an 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 scheduled for 2011. 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 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, 2010, we have a liability accrued of $8.1 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.

Central Service Center site. In 2006, we received notice from the ODEQ that our Central Service Center in southeast Portland (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 2008, we received notice that this site was added to the ODEQ’s list of sites where releases of hazardous substances have been confirmed and to 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, 2010, we have a liability accrued 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. It is near but 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. Work plans for source control investigation and a historical report were submitted to ODEQ and initial studies were completed. In 2010, ODEQ required additional studies which are underway. As of December 31, 2010, we have an estimated liability accrued of $1.1 million for the study of the sediments and riverbank groundwater and soils at the 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.

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, 2010 and 2009:

	Current Liabilities		Non-Current Liabilities	
Thousands	Dec. 31, 2010	Dec. 31, 2009	Dec. 31, 2010	Dec. 31, 2009
Gasco site	$11,366	$9,841	$38,921	$43,659

Siltronic site	720	653	201	593
Portland Harbor site	2,304	2,114	5,784	7,272
Central Service Center site	5	5	510	511
Front Street site	1	72	1,097	436
Other sites	-	-	108	123
Total	$14,396	$12,685	$46,621	$52,594

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 granted us additional authorization 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, the authorized cost deferral and interest accrual was extended through January 2010. We have filed a request with the OPUC to extend this deferral, and expect authorization during the first quarter of 2011.

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On a cumulative basis, we have recognized a total of $105.2 million for environmental costs, including legal, investigation, monitoring and remediation costs, including $4.9 million accrued and paid prior to regulatory deferral order approval. At December 31, 2010, we had a regulatory asset of $114.3 million, which includes $44.7 million of total paid expenditures to date, $61.0 million for additional environmental costs expected to be paid in the future and accrued interest of $14 million, partially offset by $5.4 million of environmental costs expensed in prior years. See table below.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon, Case Number 1012-17532. The defendants include Associated Electric & Gas Insurance Services Limited, Allianz Global Risk US Insurance Company, certain underwriters at Lloyd's London, certain London market insurance companies and ten other insurance companies. In the suit, NW Natural alleges that the defendant insurance companies issued third party liability insurance policies to NW Natural and that the defendants have breached the terms of those policies by failing to indemnify NW Natural for liabilities arising from environmental contamination at certain sites caused or alleged to be caused by its historical operations. NW Natural seeks damages in excess of $40 million in losses it has incurred to date, as well as declaratory relief for additional losses it expects to incur in the future. After seeking recovery of our environmental costs from our insurers, we believe recovery of the remainder of our deferred charges, if any, is probable through the regulatory process. Our regulatory asset will be reduced by the amount of any corresponding insurance recoveries. We continue to anticipate that our overall insurance recovery effort will extend over several years.

We anticipate that our regulatory recovery of environmental cost deferrals will not be initiated within the next 12 months because we do not expect to have completed our insurance recovery efforts during that time period. 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, 2010 and 2009:

	Non-Current Regulatory Assets	
Thousands	2010	2009
Gasco site	$74,205	$69,607
Siltronic site	3,174	2,974
Portland Harbor site	33,940	31,500
Central Service Center site	553	550
Front Street site	2,020	910
Other sites	420	507
Total	$114,312	$106,048

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

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16. Subsequent Event

On February 24, 2011, we signed an agreement to participate in a joint venture to develop gas reserves to secure a long-term gas supply for our utility customers over a 30-year period (Gas Reserves Joint Venture). During the first 10 year period, we expect the volume of gas produced to provide approximately 8 percent to 10 percent of the average annual requirements for our utility customers. Under the agreement, we will pay approximately $45 million to $55 million a year over a five year period. Our total investment is expected to be about $250 million. Under the agreement, we will be assigned a working interest in leases to certain sections of the gas field; the sections include both future and currently producing wells. Operation of the wells and the leases are governed by a joint operating agreement under which we will pay our proportionate share of operating costs to the operator of the field. The Gas Reserves Joint Venture is subject to OPUC approval. If approved by the OPUC, we expect it would provide a regulated rate of return on our net investment.

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NORTHWEST NATURAL GAS COMPANY
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Quarter ended					
Thousands, except per share amounts	March 31	June 30	Sept. 30	Dec. 31	Total	
2010						
Operating revenues	$286,529	$162,365	$95,067	$268,145	$812,106	
Net operating revenues	130,926	72,193	46,211	118,251	367,581	
Net income (loss)	43,608	6,888	(7,420)	29,591	72,667	
Basic earnings (loss) per share	1.64	0.26	(0.28)	1.11	2.73	(1)
Diluted earnings (loss) per share	1.64	0.26	(0.28)	1.11	2.73	(1)
2009						
Operating revenues	$437,355	$149,060	$116,854	$309,442	$1,012,711	
Net operating revenues	142,639	65,919	48,626	119,703	376,887	
Net income (loss)	47,363	3,086	(6,733)	31,406	75,122	
Basic earnings (loss) per share	1.79	0.12	(0.25)	1.19	2.83	(1)
Diluted earnings (loss) per share	1.78	0.12	(0.25)	1.18	2.83	(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.

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NORTHWEST NATURAL GAS COMPANY
SCHEDULE II - VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C Additions		COLUMN D Deductions	COLUMN E
Thousands (year ended Dec. 31)	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Net Write-offs	Balance at end of period
2010					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 3,125	$ 1,717	$ -	$ 1,892	$ 2,950
2009					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 2,927	$ 4,201	$ -	$ 4,003	$ 3,125
2008					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 2,890	$ 3,145	$ -	$ 3,108	$ 2,927

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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 the end of the period covered by this report, 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, 2010 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 9(a).

Item 9B. OTHER INFORMATION

None.

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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 26, 2011 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 26, 2011 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2010	Positions held during last five years
Gregg S. Kantor	53	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	49	Senior Vice President and Chief Financial Officer (2004-).
Margaret D. Kirkpatrick	56	Vice President and General Counsel (2005-); Partner in the law firm of Stoel Rives LLP (1991- 2005).
Lea Anne Doolittle	55	Senior Vice President (2008-); Vice President, Human Resources (2000-2007).
J. Keith White	57	Vice President, Business Development and Energy Supply/Chief Strategic Officer (2007-); Managing Director, Gas Operations and Wholesale Services (2005-2006); Managing Director and Chief Strategic Officer (2003-2005).
David R. Williams	57	Vice President, Utility Services (2007-); Director of Utility Operations, Districts and managed Labor Relations (2004-2006).
Grant M. Yoshihara	55	Vice President, Utility Operations (2007-); Managing Director, Utility Services (2005-2006); Director, Utility Services (2004-2005).
C. Alex Miller	53	Vice President, Finance and Regulation (2009-); Assistant Treasurer (2008-); General Manager of Rates and Regulatory Affairs (2002-2009).
Stephen P. Feltz	55	Assistant Secretary (2007-); Treasurer and Controller (1999-).

MardiLyn Saathoff	54	Deputy General Counsel (2010-); 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 26, 2011. There are no family relationships among our executive officers, directors or any person chosen to become one of our officers or directors.

NW Natural has adopted a Code of Ethics (Code) applicable to all employees and officers, 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 the Code or waivers of the Code for executive officers.

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ITEM 11. EXECUTIVE COMPENSATION

The information concerning "Executive Compensation" and "Report of the Organization and Executive Compensation Committee" contained in our definitive Proxy Statement for the May 26, 2011 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2010 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, 2010 (see Note 6 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)	82,500	n/a	270,204
Restated Stock Option Plan	490,460	$ 40.82	693,600
Employee Stock Purchase Plan	18,936	$ 41.90	152,323
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)(2)	4,635	n/a	n/a
Directors Deferred Compensation Plan (DDCP)(2)	66,027	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)(3)	108,360	n/a	n/a
Total	770,918		1,116,127

The information captioned "Beneficial Ownership of Common Stock by Directors and Executive Officers" contained in our definitive Proxy Statement for the May 26, 2011 Annual Meeting of Shareholders is incorporated herein by reference.

(1) Shares issued pursuant to the LTIP do not include an exercise price, but are payable when the award criteria are satisfied. If the maximum awards were paid pursuant to the performance-based awards outstanding at December 31, 2010, the number of shares shown in column (a) would increase by 82,500 shares and the number of shares shown in column (c) would decrease by 165,000 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

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(3) 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.

(4) Effective January 1, 2005, the EDCP and DDCP were replaced by the 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 participants stock accounts. The right of each participant in the DCP is that of a general, unsecured creditor of the Company.

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 26, 2011 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned "2010 and 2009 Audit Firm Fees" in the Company's definitive Proxy Statement for the May 26, 2011 Annual Meeting of Shareholders is hereby incorporated by reference.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

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

2. List of Exhibits filed:

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

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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 25, 2011 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 President and Chief Executive Officer	Principal Executive Officer and Director	February 25, 2011
/s/ David H. Anderson David H. Anderson Senior Vice President and Chief Financial Officer	Principal Financial Officer	February 25, 2011
/s/ Stephen P. Feltz Stephen P. Feltz Treasurer and Controller	Principal Accounting Officer	February 25, 2011
/s/ Timothy P. Boyle Timothy P. Boyle	Director	)
/s/Martha L. Byorum Martha L. Byorum	Director	)
/s/ John D. Carter John D. Carter	Director	)
/s/ Mark S. Dodson Mark S. Dodson	Director	)
/s/ C. Scott Gibson C. Scott Gibson	Director	) February 25, 2011
/s/ Tod R. Hamachek Tod R. Hamachek	Director	)
/s/ Jane L. Peverett Jane L. Peverett	Director	)

		)
/s/ George J. Puentes	Director	)
George J. Puentes		)
		)
/s/ Kenneth Thrasher	Director	)
Kenneth Thrasher		)
		)
/s/ Russell F. Tromley	Director	)
Russell F. Tromley		)

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NORTHWEST NATURAL GAS COMPANY

EXHIBIT INDEX
To
Annual Report on Form 10-K
For Fiscal Year Ended
December 31, 2010

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).
*4b.	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).
*4c.	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).
*4d.	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).
*4e.	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).
*4f.	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 4 to Form 10-Q dated November 5, 2010, File No. 1-15973).

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*4g.	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 institution with JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated herein by reference to Exhibit 4i.(1) to Form 10-K for 2008, File No. 1-15973).
*4h.	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).
*4i.	Letter Agreement among the Company, JPMorgan Chase Bank, N.A., Bank of America, N.A., U.S. Bank National Association, Wachovia Bank, National Association, Wells Fargo Bank, N.A., Bank of America, N.A., Successor by merger to Merrill Lynch Bank USA, and UBS Loan Finance LLC, dated October 29, 2009 (incorporated herein by reference to Exhibit 4i. to Form 10-K for 2009, File No. 1-15973).
*4j.	Distribution Agreement, dated March 18, 2009, among Banc of America Securities LLC, UBS Securities LLC, J.P. Morgan Securities Inc., and Piper Jaffray and Co. (Incorporated herein by reference to Exhibit 1.1 to Form 8-K dated March 23, 2009, File No. 1-15973).
*4k.	Form of Letter Agreement, dated August 24, 2009, among Banc of America Securities, LLC, UBS Securities LLC, J.P. Morgan Securities Inc., Piper Jaffray & Co. and Wells Fargo Securities, LLC (incorporated herein by reference to Exhibit 4k. to Form 10-K for 2009, File No. 1-15973).
*4l.	Form of Unsecured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.2 to Form 8-K dated October 4, 2004, File No. 1-15973).
*10a.(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).
*10a.(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).
*10a.(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).
*10a.(4)	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).
*10a.(5)	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. 001-15973).
*10a.(6)	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).

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*10a.(7)	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).
*10a.(8)	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).
*10a.(9)	Firm Transportation Service Agreement, dated October 22, 1993, between the Company and Pacific Gas Transmission Company (incorporated herein by reference to Exhibit 10j.(10) to Form 10-K for 2008, File No. 1-15973).
*10a.(10)	Service Agreement (100310), dated January 21, 2008, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(11) to Form 10-K for 2008, File No. 1-15973).
*10a.(11)	Service Agreement, dated January 21, 2008, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(12) to Form 10-K for 2008, File No. 1-15973).
*10a.(12)	Service Agreement (Gas Storage Service), dated January 12, 1994, between the Company and Northwest Pipeline Corporation (incorporated herein by reference to Exhibit 10j.(13) to Form 10-K for 2008, File No. 1-15973).
*10a.(13)	Service Agreement (100309), dated January 21, 2008, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(14) to Form 10-K for 2008, File No. 1-15973).
*10a.(14)	Service Agreement (100308), dated January 12, 1994, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(15) to Form 10-K for 2008, File No. 1-15973).
*10a.(15)	Service Agreement, dated January 20, 1995, between the Company and NOVA Gas Transmission Ltd (incorporated herein by reference to Exhibit 10j.(16) to Form 10-K for 2008, File No. 1-15973).
*10a.(16)	Service Agreement, dated November 1, 2004, between the Company and TransCanada PipeLines Limited (incorporated herein by reference to Exhibit 10j.(17) to Form 10-K for 2008, File No. 1-15973).
*10a.(17)	Service Agreement, dated October 24, 2008, between Foothills Pipe Lines Ltd. and the Company (incorporated herein by reference to Exhibit 10j.(18) to Form 10-K for 2008, File No. 1-15973).
*10a.(18)	Amendment and Restatement of Firm Transportation Service Agreement, dated November 1, 2004, between Terasen Gas Inc. and the Company (incorporated herein by reference to Exhibit 10j.(19) to Form 10-K for 2008, File No. 1-15973)..

12	Statement re computation of ratios of earnings to fixed charges.
21	Subsidiaries of Northwest Natural Gas Company
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.

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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 2010 Restatement (incorporated herein by reference to Exhibit 10b. to Form 10-K for 2009, File No. 1-15973).
*10c.	Supplemental Executive Retirement Plan, effective September 1, 2004 restated 2010 (incorporated herein by reference to Exhibit 10c. to Form 10-K for 2009, File No. 1-15973).
*10d.	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).
*10e.	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).
*10f.	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).
*10g.	Restated Stock Option Plan, as amended effective December 14, 2006 (incorporated herein by reference to Exhibit 10c. to Form 10-K for 2006, File No. 1-15973).
*10h.	Form of Restated Stock Option Plan Agreement (incorporated herein by reference to Exhibit 10h. to Form 10-K for 2009, File No. 1-15973).
*10i.	Executive Deferred Compensation Plan, effective as of January 1, 1987, restated as of February 26, 2009 (incorporated herein by reference to Exhibit 10(e). to Form 10-K for 2008, File No. 1-15973).
*10j.	Directors Deferred Compensation Plan, effective June 1, 1981, restated as of February 26, 2009 (incorporated herein by reference to Exhibit 10(f). to Form 10-K for 2008, File No. 1-15973).
*10k.	Deferred Compensation Plan for Directors and Executives effective January 1, 2005, restated as of January 1, 2010 (incorporated herein by reference to Exhibit 10k. to Form 10-K for 2009, File No. 1-15973).
*10l.	

	Form of Indemnity Agreement as entered into between the Company and each director and certain executive officers (incorporated herein by reference to Exhibit 10l. to Form 10-K for 2009, File No. 1-15973).
*10l.(1)	Form of Indemnity Agreement as entered into between the Company and certain executive officers (incorporated herein by reference to Exhibit 10l.(1) to Form 10-K for 2009, File No. 1-15973).
*10m.	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).

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*10n.	Executive Annual Incentive Plan, effective February 25, 2010 (incorporated herein by reference to Exhibit 10n. to Form 10-K for 2009, File No. 1-15973).
*10o.	Form of Agreement to Recoupment Provisions of Executive Annual Incentive Plan, effective as of January 1, 2010 (incorporated herein by reference to Exhibit 10o. to Form 10-K for 2009, File No. 1-15973).
*10p.	Form of Change in Control Severance Agreement between the Company and each executive officer (incorporated herein by reference to Exhibit 10o. to Form 10-K for 2008, File No. 1-15973).
*10q.	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).
*10r.	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. 1-15973).
10s.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan.
*10t.	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).
*10u.	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).
*10v.	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).
*10w.	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).
*10x.	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).
*10y.	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).
*10z.	

	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan relating to a special award to an executive officer (incorporated herein by reference to Exhibit 10z. to Form 10-K for 2009, File No. 1-15973).
10z.(1)	Separation Agreement with an executive officer dated January 7, 2011.

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*Incorporated herein by reference as indicated

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