NORTHWEST NATURAL GAS CO
Form 10-K
February 26, 2010

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, 2009

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 [ ] 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. [ ]

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, 2009, the registrant had 26,513,188 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 $1,162,927,287.

At February 23, 2010, 26,533,028 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 2010 Annual Meeting of Shareholders, are incorporated by reference in Part III.

NORTHWEST NATURAL GAS COMPANY
Annual Report to Securities and Exchange Commission
on Form 10-K
For the Fiscal Year Ended December 31, 2009
Table of Contents

Table of Contents

GLOSSARY OF TERMS

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

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

Btu: British thermal unit, a basic unit of thermal energy measurement. One Btu equals the energy required to raise one pound of water one degree Fahrenheit at atmospheric pressure and 60 degrees Fahrenheit. One hundred thousand Btu's equal one therm.

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

Cost of gas: the delivered cost of gas commodity sold to customers, including the cost of gas purchases, gas withdrawn from storage inventory, gains and losses from commodity hedges, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost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

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.

Demand charge: a component in all core utility customer rates that covers the cost of securing firm pipeline

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

Liquefied natural gas (LNG): the cryogenic liquid form of natural gas. To reach a liquid form at atmospheric pressure, natural gas must be cooled to approximately -260 degrees Fahrenheit.

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

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

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

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

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

Utility margin: utility gross revenues less the associated cost of gas and applicable revenue taxes. Also referred

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.

to as utility net operating revenues.

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

Table of Contents

Forward-Looking Statements

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;
- growth;
- development of projects;
- competition;
- exploration of new gas supplies;
- the benefits of liquefied natural gas;
- estimated expenditures;
- costs of compliance;
- potential efficiencies;
- impacts of new laws and regulations;
- projected obligations under retirement plans;
- adequacy of and shift in mix of gas supplies;
- adequacy of regulatory deferrals; and
- environmental, regulatory and insurance 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 caution you therefore 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.

Table of Contents

NORTHWEST NATURAL GAS COMPANY
PART I

ITEM 1. BUSINESS

General

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

Business Segments

We operate in two primary reportable business segments, Local Gas Distribution and Gas Storage. We also have other investments and business activities not specifically related to one of these two reporting segments 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 and terms approved by the Oregon Public Utility Commission (OPUC) or by the Washington Utilities and Transportation Commission (WUTC). Gas distribution also includes transporting gas owned by large customers from the interstate pipeline connection, or city gate, to the customers' facilities for a fee, also approved by the OPUC or WUTC. Approximately 92 percent of our consolidated assets at December 31, 2009, and 88 percent of our consolidated net income in 2009, were related to the local gas distribution segment. The OPUC has allocated to us as our exclusive service area a major portion of western Oregon, including the Portland metropolitan area, most of the Willamette Valley and the coastal area from Astoria to Coos Bay. We also hold certificates from the WUTC granting us exclusive rights to serve portions of three southwest Washington counties bordering the Columbia River. We provide gas service in 124 cities and neighboring communities in 15 Oregon counties, as well as in 16 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 2009, we had approximately 668,000 total utility customers, consisting of approximately 605,000 residential, 62,000 commercial and 1,000 industrial sales and transportation customers. Approximately 90 percent of our utility customers are located in Oregon and 10 percent are in Washington. Industries we serve include: pulp, paper and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery and textiles; the manufacture of asphalt, concrete and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation. No individual utility customer or industry accounts for a significant portion of our revenues.

See Note 2 for further information on total assets and results of operations for the years ended December 31, 2009, 2008 and 2007.

Utility Gas Supply, Storage and Transportation Capacity

We meet the expected needs of our core utility customers through natural gas purchases from a variety of suppliers. Our supply and capacity plan is based on forecasted customer requirements and takes into account estimated load growth by type of customer, attrition, conservation, distribution system constraints, interstate pipeline capacity and contractual limitations and the forecasted 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.

Table of Contents

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 use of physical assets (e.g. gas storage and long-term gas reserves) and financial instruments (e.g. financial hedge contracts such as price swaps) to manage commodity price variability; and
- Cost recovery—Managing gas purchase costs prudently to minimize the risks associated with regulatory review and recovery of gas acquisition costs.

To achieve our gas acquisition strategy, we employ a gas purchasing strategy that emphasizes a diversity of supply, 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 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 are considering shifting more of our supply mix to the U.S. Rocky Mountains based on projections of declining gas imports from western Canada and increased gas production in the U.S. Rocky Mountains. We believe that the cost of natural gas coming from these regions will continue to track respective market prices. Several projects have been built and more are proposed to increase pipeline capacity out of the U.S. Rocky Mountain region, while new technology to extract shale gas resources in recent years continues to increase the availability of gas supply throughout North America. In addition, we also believe the potential development of a liquefied natural gas (LNG) import terminal would benefit the Pacific Northwest. If constructed, an LNG import terminal would introduce a new source of gas supply to our utility customers and the region, thereby increasing the diversity of available sources of energy and increasing the overall supply of natural gas available to meet future demand growth in the region.

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 supply gas to us on a daily basis, and seasonal exchange purchase and sale contracts. We try to maintain a diversified portfolio of purchase arrangements.

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

Table of Contents

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 various 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 directly with gas suppliers;
- negotiating financial derivative instruments that effectively convert the floating price in a physical supply contract to a fixed price (referred to as 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 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,” 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 reduces our utility’s cost of gas, as well as generates incremental revenues from a regulatory incentive sharing mechanism that are included in our gas storage business segment. See Note 2.

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 purchased, and we attempt to minimize risks associated with gas cost recovery through:

- re-setting customer rates annually for changes in forecasted purchased gas costs and recovery of customer deferrals of prior year’s actual versus forecasted gas purchase costs. (see Part II, Item 7., “Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment”);
- aligning customer and shareholder interests, such as through the use of our Purchased Gas Adjustment (PGA) incentive sharing mechanism, weather normalization, conservation, and gas storage sharing mechanisms (see Part II, Item 7., “Results of Operations—Regulatory Matters”); and
- periodic review of regulatory deferrals with state regulatory commissions and key customer groups.

Cost of Gas

The cost of gas to supply our core utility customers primarily consists of the purchase price paid to suppliers, charges paid to pipeline companies to store and transport 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 been dramatic 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, 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 disruptions, national and worldwide economic and political conditions, and the price and availability of alternative fuels. We are in a favorable position

with respect to gas production because of the proximity of our service territory to supply basins in western Canada and the U.S. Rocky Mountains, where some growth in gas production is expected to continue for the foreseeable future.

Table of Contents

Transportation cost. Pipeline transportation rates charged by our pipeline suppliers have been relatively stable over the last several years. These rates periodically change when pipeline suppliers get approval from the Federal Energy Regulatory Commission (FERC). Pipeline transportation rate increases or decreases are generally passed on to our customers through annual PGA mechanisms.

Gas price hedging. We seek to mitigate the effects of higher gas commodity prices and price volatility on core utility customers by using our underground storage facilities strategically and by entering into financial hedge contracts 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.

Managing the Cost of Gas

We manage natural gas commodity price risk through active physical and financial hedging programs. Our financial hedge contracts make up a majority of our commodity price hedging activity, and these contracts are with a variety of investment-grade credit counterparties, typically with credit ratings of AA- or higher. See Part II, Item 7A., "Quantitative and Qualitative Disclosures About Market Risk—Credit Risk—Credit exposure to financial derivative counterparties." Under our financial hedge program, we 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 from 5 to 15 percent of our annual gas supply requirements into storage during the summer 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 significant cost savings. The other two storage facilities are owned and operated by our primary pipeline supplier.

The intended effect of our physical and financial hedging programs is to manage the price exposure for a majority of our gas supply portfolio for the following gas contract year, which begins November 1st of each year, with prices normally hedged for between 50 and 75 percent of year round supplies, including more than 80 percent of our expected winter-heating season supplies based on forecasted customer requirements. We are authorized by our Board of Directors to hedge up to 100 percent of our gas requirements for the next gas contract year.

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 design day 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 million therms. We are currently capable of meeting over 60 percent of our firm customer maximum design day requirements with storage and peaking supply sources located within or adjacent to our service territory, while the remaining gas supply requirements would be met by gas purchases under firm contracts. Optimal utilization of storage and peaking facilities on our design day reduces the cost and dependency on firm interstate pipeline transportation. On January 5, 2004, we experienced our current record firm customer sendout of 7.2 million therms, and a total sendout of 8.9 million therms, on a day that was approximately 9 degrees Fahrenheit warmer than the design day temperature. That January 2004 cold weather event lasted about 10 days, and the actual firm customer sendout each day provided data indicating that load forecasting models required very little re-calibration. Similar cold temperatures experienced in December 2008 and December 2009 produced

very high sendout days but firm sendout in December 2009 was still about 3 percent below our 2004 record. This primarily reflects a decline in average customer usage. Accordingly, we believe that our supplies would be sufficient to meet firm customer demand if we were to experience design day conditions. We will continue to evaluate and update our forecasts of design day requirements in connection with our integrated resource plan (IRP) process (see "Integrated Resource Plan," below).

Table of Contents

The following table shows the sources of supply that are projected to be used to satisfy the design day sendout for the 2009-2010 winter heating season:

Projected Sources of Supply for Design Day Sendout

Sources of Supply	Therms (in millions)	Percent
Firm supply purchases	3.3	37
Mist underground storage (utility only)	2.4	27
Company-owned LNG storage	1.8	20
Off-system firm storage contracts	1.1	12
Recall agreements	0.4	4
Total	9.0	100

We believe the combination of the natural gas supply purchases under contract, our peaking supplies and the transportation capacity held under contract on the interstate pipelines sufficiently satisfies the needs of existing core utility customers and positions the utility to meet future requirements.

Core Utility Market Basic Supply

We purchase gas for our core utility customers from a variety of suppliers located in western Canada and the U.S. Rocky Mountain area. Currently, about 60 to 70 percent of our supply comes from Canada, with the balance coming primarily from the U.S. Rocky Mountain region. We are considering shifting more of our supply mix to the U.S. Rocky Mountains based on projections of declining gas imports from western Canada and increased gas production in the U.S. Rocky Mountains. At December 31, 2009, we had 29 firm contracts with 20 suppliers and remaining terms ranging from five months to five years, which provide for a maximum of 1.55 million therms of firm gas per day during the peak winter heating season and 0.8 million therms per day during the entire year. These contracts have a variety of pricing structures and purchase obligations. In addition, we have another 0.95 million therms of firm gas capacity whereby we can purchase contract or spot gas supplies for delivery to our system during the peak winter heating season. During 2009, we purchased 783 million therms of gas under contracts with the following durations:

Contract Duration (primary terms)	Percent of Purchases
Long-term (one year or longer)	49
Short-term (more than one month, less than one year)	18
Spot (one month or less)	33
Total	100

We regularly renew or replace our gas supply contracts with new agreements with a variety of existing and new suppliers. Aside from the optimization of our core utility gas supplies by the independent energy marketing company (see “Gas Acquisition Strategy—Asset optimization,” above), our daily contract requirements are provided by multiple sources with no more than three suppliers providing between 5 and 10 percent of our average daily contract volumes. Firm year-round supply contracts have remaining terms ranging from one to five years. Currently, all term gas supply contracts use price formulas tied to monthly index prices. We hedge a majority of these contracts each year using financial instruments as part of our gas purchasing strategy (see “Managing the Cost of Gas,” above).

In addition to the year-round contracts, we continue to contract in advance for firm gas supplies to be delivered only during the winter heating season primarily under short-term contracts. During 2009, new short-term purchase agreements were entered into with between 15 and 20 suppliers. These agreements provide for a total of up to 1.1

million therms per day during the 2009-2010 heating season. We intend to enter into new purchase agreements in 2010 for equivalent volumes of gas with existing or new suppliers, as needed, to replace contracts that will expire during 2010.

Table of Contents

We also buy gas on the spot market as needed to meet core utility customer demand. We have flexibility under the terms of some of our firm supply contracts, 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 supplies with gas from storage facilities we own or that are contractually committed to us. Gas is generally purchased and stored during periods of low demand for use at a later time during periods of peak demand. In addition to enabling us to meet our peak demand, these facilities make it possible to lower the annual average cost of gas by allowing us to minimize our pipeline 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 Oregon core utility customers from our underground gas storage facility in the Mist gas storage field. Including the latest expansions in 2008, this facility has a maximum daily deliverability of 5.1 million therms and a total working gas capacity of about 16 Bcf. In May 2008, a total of 100,000 therms per day of Mist storage capacity that had previously been available for storage services was recalled and committed to use for core utility customers. This was the first recalled capacity since 2004. In May 2009, another 100,000 therms per day of Mist storage withdrawal capacity that had previously been available for interstate storage services was recalled by the utility and committed to use for its core customers. Under our regulatory agreement with the OPUC, non-utility gas storage at Mist has been developed in advance of core utility customer needs for interstate storage services and can be recalled by the utility to serve utility customers. 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 market now has 2.5 million therms per day of deliverability and approximately 9.4 Bcf of working gas committed from the Mist storage facility.

We also have contracts with the Williams Companies' Northwest Pipeline (Northwest Pipeline) for firm gas storage services from an underground storage facility in Jackson Prairie near Chehalis, Washington, and 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 the peak winter heating season. These two facilities provide a maximum combined daily deliverability of 1.8 million therms and a total seasonal capacity of 17 million therms.

Recallable capacity from transportation customers. We also have contracts with one electric generator and two industrial customers that together provide 390,000 therms per day of recallable pipeline capacity and supply. Another contract for 52,000 therms per day of year-round pipeline capacity expired on June 30, 2009, and the capacity reverted back to the industrial customer. A replacement agreement to reacquire the expired capacity was completed later in 2009 (see "Transportation—Transportation agreements," below).

Table of Contents

Transportation

Single transportation pipeline. Our distribution system is directly connected to a single interstate pipeline, Northwest Pipeline. Although we are dependent on a single pipeline, the pipeline's gas flows are bi-directional and, as such, transports gas into the Portland metropolitan market from two directions: (1) the north, which brings supplies from British Columbia and Alberta supply basins; and (2) the east, which brings supplies from Alberta as well as the U.S. Rocky Mountain supply basins. In 2003 a federal order requiring Northwest Pipeline to replace its 26-inch mainline from the Canadian border to our service territory underscored the need for pipeline transportation diversity. That replacement project was completed by Northwest Pipeline in November 2006. We are pursuing options to further diversify our pipeline transportation paths. Specifically, we are 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 gas distribution system. In August 2007, we entered into an agreement with GTN for the purpose of jointly developing, owning and operating this proposed pipeline. Additionally, we entered into precedent agreements to become a shipper on the Palomar Pipeline. If constructed, this pipeline would provide an alternate transportation path for gas purchases from Alberta and the U.S. Rocky Mountains that currently move through the Northwest Pipeline system (See Part II, Item 7., "2010 Outlook—Strategic Opportunities—Pipeline diversification").

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

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

We also have an agreement with Northwest Pipeline that 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 gas supply transportation contract starting no earlier than 2012 nor later than 2017, with the term extending through 2046. This contract consists of 120,000 therms per day on Northwest Pipeline from the U.S. Rocky Mountain region.

Beginning in December 2009, we took assignment of a long-term firm transportation contract from an industrial customer for approximately 40,000 therms of Northwest Pipeline capacity to serve our utility customers.

In addition, we have firm long-term pipeline transportation contracts with two other major transporters located in Canada. One contract extends through October 2014 and provides approximately 600,000 therms per day of firm gas transportation from Station 2 in northern British Columbia to the Huntingdon/Sumas connection with Northwest Pipeline at the U.S./Canadian border. Another contract extends through October 2020 and provides approximately 470,000 therms per day of firm gas transportation from southeastern British Columbia to the same Huntingdon/Sumas connection with Northwest Pipeline. Our capacity on this second contract is matched with companion contracts for pipeline capacity on the TransCanada BC system and NIT system 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 transportation agreements within the U.S., and Canadian federal or provincial authorities establish rates for service under agreements with the Canadian pipelines over which we ship gas.

Table of Contents

Integrated Resource Plan

The OPUC and WUTC have implemented integrated resource planning processes under which utilities develop plans defining alternative growth scenarios and resource acquisition strategies. These plans are consistent with state and energy policy and include:

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

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

Competition and Marketing

Competition with Other Energy Products

We have no direct competition in our service area from other natural gas distributors. However, for residential customers, we compete primarily with electricity, fuel oil and propane. We also compete with electricity and fuel oil for commercial applications. In the industrial market, we compete with all forms of energy, including competition from third-party sellers of natural gas commodity. Competition among gas suppliers is based on price, perceived environmental impact, sustainability, reliability, efficiency and performance, market conditions, technology and legislative policy. Whether or not we provide the gas supplies to serve our transportation-eligible customers, our net margins are not materially affected because we generally do not make any margin on the commodity sales to our utility customers (see "Industrial Markets," below).

Residential and Commercial Markets

The relatively low market saturation of natural gas in residential single-family dwellings in our service territory, estimated at approximately 55 percent, and our operating convenience and environmental advantage over fuel oil, provides the potential for continuing growth from residential and commercial conversions. In 2009, 5,407 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 2009 was 5,453. This represents a 12-month growth rate of 0.8 percent. 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 percent of gross operating revenues, while industrial customers account for about 40 to 45 percent of volumes and about 12 percent of gross revenues. The remaining 3 percent of gross operating revenues is derived from miscellaneous services and other regulatory charges.

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 revenues or margins.

The OPUC and WUTC have approved transportation tariffs under which we may contract with customers to deliver customer-owned gas. Transportation tariffs available to industrial customers are priced at our sales service rate less the commodity cost included in that rate. Therefore, our transportation margins (i.e. sales minus the cost of gas sold) are unaffected financially if industrial customers buy commodity supplies directly from marketers rather than purchasing gas from us, as long as they remain on a tariff or contract with the same 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, among other levels of service, and these choices can positively or negatively affect margin as firm service has a higher 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.

Table of Contents

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 cost of gas tariff complete the agreed upon term of their service. In the case of customers switching out-of-cycle from transportation to sales service, the customer will be charged the cost of incremental gas supply in accordance with our regulatory tariff.

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

Gas Storage

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

Approximately 7 percent of our consolidated assets at December 31, 2009, and 12 percent of our consolidated net income in 2009, are related to the gas storage business segment. For each of the years ended December 31, 2009, 2008 and 2007, this business segment derived its revenues from asset optimization services performed by an independent energy marketing company and from multi-year gas storage contracts with less than 10 customers who contract for service at our Mist storage facility. The total working gas capacity at our Mist gas storage facility is approximately 16 Bcf. Of this capacity, approximately 9.4 Bcf, or 59 percent of storage capacity, is currently used by our utility, and the remaining 6.6 Bcf, or 41 percent, is committed to gas storage customers primarily under firm storage contracts. See Note 2 for more information on total assets and results of operations for the years ended December 31, 2009, 2008 and 2007.

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

We are currently in the process of developing a second underground gas storage facility and related pipeline in the Fresno, California area. This project is expected to serve the California market. All permits were obtained to begin construction in 2010 (see "Gas storage development," below).

Asset optimization. We contract with an independent energy marketing company to optimize the value of our unused storage and pipeline transportation assets, primarily through the use of commodity transactions and pipeline capacity release transactions.

Seasonality of business. Generally, gas storage revenues do not follow seasonal patterns similar to those experienced by the utility because rates for firm storage contracts are primarily in the form of fixed monthly reservation charges and are not affected by customer usage. However, there is some seasonal variation from the optimization of available 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.

Table of Contents

Gas storage customers. Our gas storage business segment generally enters into contracts with customers for firm storage capacity with terms ranging from one to 10 years. Currently, our gas storage revenues are primarily derived from a few large storage customers who provide energy related services, including natural gas distribution, electric generation and energy marketing companies. Five storage customers currently account for over 90 percent of our existing gas storage capacity, with the largest customer accounting for about half of total capacity. These five customers have contracts that expire at various dates between March 2010 and April 2017.

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

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

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

Gas storage development. In September 2007, we entered into a joint project agreement with Pacific Gas & Electric Company (PG&E) to develop an underground natural gas storage facility near Fresno, California. At that time, we formed a wholly-owned subsidiary, Gill Ranch Storage, LLC (Gill Ranch), to plan and develop the project and to operate the facility. In July 2008, Gill Ranch filed an application with the California Public Utilities Commission (CPUC) for a Certificate of Public Convenience and Necessity (CPCN). In October 2009, we received an order from the CPUC approving our CPCN. Gill Ranch's provision of market-based rate storage services in California will be subject to CPUC regulation including, but not limited to, service terms and conditions, tariff compliance, systems of accounts, securities issuances, lien grants and sales of property. Our share of the total project cost is estimated to be between $160 million and $180 million, representing 75 percent of the total cost of the initial development, which includes our share of an estimated total 20 Bcf of gas storage capacity and approximately 27 miles of gas transmission pipeline. We are currently in the process of hiring key staff for our gas storage business. In January 2010, we began construction of the Gill Ranch facility. The initial development of the gas storage facility at Gill Ranch is currently targeted to be in-service by the end of the third quarter of 2010.

While our primary focus for growing the gas storage business is on the development at Gill Ranch, we also plan to continue expanding our interstate storage facilities at Mist, Oregon. This past year, we completed three-dimensional seismic surveys and initiated engineering work for a new 3 to 4 Bcf expansion at Mist. Pending confirmation of customer interest in contracting for the additional capacity, we expect to move forward with the project next year and would target a 2011 in-service date. The total project cost estimates are between $45 million and $55 million. This estimated cost range includes the development of a second compression station and a pipeline gathering system at Mist that will enable future storage expansions.

Other

We have non-utility investments and other business activities which are aggregated and reported as a business segment called "Other." Although in the aggregate these investments and activities are not material, we identify and report them as a stand-alone segment based on our current organization structure and decision-making process and because these business investments and activities are not specifically related to our utility or gas storage

segments. This segment primarily consists of an equity method investment in a joint venture to build and operate an interstate gas transmission pipeline in Oregon (see Part II, Item 7., "2010 Outlook—Strategic Opportunities—Pipeline diversification," below) and pipeline assets in our wholly-owned NNG Financial Corporation, as well as some operating and non-operating expenses of the parent company that cannot be charged to utility operations. Approximately 1 percent of our consolidated assets and consolidated net income are related to activities in the "Other" business segment. See Note 2 for more information on total assets and results of operations for the three years ended December 31, 2009.

Table of Contents

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates, terms of services, and systems of accounts established by the OPUC, the WUTC, the FERC and, with respect to Gill Ranch, the CPUC. The OPUC and WUTC also regulate our issuance of securities, as will 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. Later this year, we expect to file a storage service tariff with the CPUC with respect to Gill Ranch. 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 and rate approval orders to file every three years either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for the interstate storage service. For further information, see Part II, Item 7., "Results of Operations—Regulatory Matters," below and "Business Segments—Gas Storage," above.

Environmental Issues

Properties and Facilities

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

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

We own, or previously owned, properties currently being investigated that may require environmental response, including: a property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (Gasco site); a property adjacent to the Gasco site that is now the location of a manufacturing plant owned by Siltronic Corporation (Siltronic site); an area adjacent to the Gasco and the Siltronic sites in the Willamette River that has been listed by the U.S. Environmental Protection Agency as a Superfund site for which we have been identified as one of a number of potentially responsible parties (Portland Harbor site); the former location of a gas manufacturing plant operated by our predecessor that is outside the geographic scope of the current Portland Harbor site (Front Street site); and the former site of three manufactured gas 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 11, for a further discussion of potential environmental responses, related costs and regulatory and insurance recovery.

Table of Contents

Future Environmental Issues

We recognize that our businesses are likely to be impacted by future carbon constraints. A variety of legislative and regulatory measures to address greenhouse gas emissions are in various phases of discussion or implementation. These include proposed international standards, proposed federal legislation and proposed or enacted state actions to develop statewide or regional programs, each of which have imposed or would impose measures to achieve reductions in greenhouse gas emissions. For example, in December 2009, the U.S. Environmental Protection Agency (EPA) officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal Clean Air Act. In late September 2009, the EPA proposed two sets of regulations in anticipation of finalizing its findings that would require a reduction in emissions of greenhouse gases from motor vehicles and that could also lead to the imposition of greenhouse gas emission limitations in Clean Air Act permits for certain stationary sources. Additionally, in September 2009, the EPA issued a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas emission sources in the United States beginning in 2011 for emissions occurring on or after January 1, 2010. This new rule also requires certain facilities that emit 25,000 metric tons or more of CO2 equivalents per year and certain industries to report certain greenhouse gas emissions data from that facility or industry to the EPA on an annual basis. As we are part of the natural gas distribution industry required to report these emissions, we are evaluating our obligations under this new rule in light of additional guidance to be released by the EPA.

The outcome of 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 imposing reporting obligations on, or 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 a 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. Our President and CEO is a commissioner on the Oregon Global Warming Commission. We continue to engage in policy development and in identifying ways to reduce greenhouse gas emissions associated with our operations and our customers' gas use, including the introduction of the Smart Energy program, which allows customers to contribute funds to projects that offset greenhouse gases produced from their natural gas use.

Employees

At December 31, 2009, our workforce consisted of 646 members of the Office and Professional Employees International Union (OPEIU), Local No. 11, AFL-CIO, and 415 management level and other non-union employees (see Part II, Item 7., "2010 Outlook—Strategic Opportunities—Business process improvements"). 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 union agreement.

Table of Contents

Additions to Infrastructure

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 the development of additional gas storage facilities. In 2010, utility capital expenditures are estimated to be between $80 and $90 million, and non-utility capital investments are estimated to be between $120 and $145 million for development projects that are currently in process, including our storage expansion at Mist. For the years 2010-2014, capital expenditures for the utility are estimated to be between $400 and $500 million, while the amount for gas storage and other investments after 2010 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.

Available Information

We file annual, quarterly and special reports and other information with the Securities and Exchange Commission (SEC). Reports, proxy statements and other information filed by us can be read and copied at the Public Reference Room of the SEC, 100 F Street, N.E., Washington, D.C. 20549. You can obtain additional information about the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains a website (http://www.sec.gov) that contains reports, proxy statements and other information that we file electronically. In addition, we make available on our website (http://www.nwnatural.com), our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports, as well as proxy materials, filed or furnished pursuant to Section 13(a) or 15(d) and Section 14 of the Securities Exchange Act of 1934, as amended (Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

We have adopted a Code of Ethics for all employees and a Financial Code of Ethics that applies to senior financial employees, both of which are available on our website. We intend to disclose amendments to, and any waivers from, such codes of ethics on our website. Our Corporate Governance Standards, Director Independence Standards, charters of each of the committees of the Board of Directors and additional information about us are also available 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. When considering any investment in our securities, investors should 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. Additional risks and uncertainties not presently known or currently deemed immaterial also may impair our business operations. This list is not exhaustive and the order of presentation does not reflect management’s determination of priority or likelihood.

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 customer additions and 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, unemployment rates and mortgage defaults have risen, and the value of homes and investment assets 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. Our operations and financial results are affected by these economic conditions. Less new housing construction, fewer conversions to natural gas, higher levels of residential foreclosures and vacancies, and personal and business bankruptcies or reduced spending could all result in a decline in energy consumption and customer growth, 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.

Table of Contents

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

The OPUC and WUTC have general regulatory authority over our utility business in Oregon and Washington, respectively, including 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.

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

In addition, in the normal course of our business we may place assets in service or incur higher 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.

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

In recent years, we have seen a significant increase in the volatility of natural gas commodity prices, primarily due to shifts in the balance of supply and demand. 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, including LNG, 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. The cost we pay for natural gas is generally passed through to our customers through an annual PGA rate adjustment in Oregon and Washington (see below). Significant increases in the commodity price of natural gas raises the cost of energy to our existing customers, thereby causing those customers to conserve or potentially switch to alternate sources of energy. Significant price increases could also cause new home builders and commercial developers to select heating systems other than natural gas. Decreases in the volume of gas we sell could reduce our earnings in the absence of decoupled rate structures, and a decline in customers could slow growth in our future earnings.

Higher gas prices may also cause us to experience an increase in short-term debt and temporarily reduce liquidity because we pay suppliers for gas when it is purchased, which can be 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.

Table of Contents

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.

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.

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.

Table of Contents

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.

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 and storage businesses are subject to increased competition which could negatively affect our results of operations.

In the residential market, our gas distribution business competes primarily with suppliers of electricity, fuel oil, 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, reliability, efficiency and performance.

Higher natural gas prices have at times eroded, or in some cases eliminated, the competitive price advantage of natural gas over other energy sources. 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.

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

Reliance on third parties to supply natural gas risk. We rely on third parties to supply substantially all of the natural gas we store and deliver, 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.

Table of Contents

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 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. 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

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. We are in the early development stage on the Palomar gas transmission pipeline in Oregon, and we have begun construction of Gill Ranch gas storage facility in California. We may also engage in other business development projects in the future, including expansion of our storage facility at Mist. 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, changes in market prices, and operating cost increases. Additionally, natural gas storage and transportation markets are intensely competitive, both within the natural gas industry and with alternative sources of energy. To complete our business development projects, we will need to secure financing from willing investors at reasonable cost. If credit markets are inaccessible, we may be unable fund our business development projects at acceptable interest rates within a timeframe favorable for completing the project. Similarly, an inability to obtain the necessary state permits, or arrange for sufficient supplier commitments could impact the viability of an LNG terminal on the Columbia river and may mean that we would not proceed with the western portion of Palomar. One or more of these events may mean that our equity investments could become impaired and such impairment could have an adverse effect on our financial condition 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 non-utility development projects, including Palomar and Gill Ranch, and we may acquire interests in other similar types of projects in the future. Under these types of business arrangements, we may not be able to fully direct the management and policies of the business relationships, and other participants in those relationships may take action contrary to our interests. In addition, other participants may withdraw from the project, become financially distressed or bankrupt, or have economic or other business interests or goals that are inconsistent with ours. Although we have contractual and other legal remedies to enforce our interests, if a participant in one of these business arrangements acts contrary to our interests, it could adversely impact the project as well as our financial condition, results of operations and cash flows.

Environmental risk. Certain of our properties and facilities may pose environmental risks requiring remediation, the cost of which could adversely affect our 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 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 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.

Table of Contents

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 customer rates.

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 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 impose on us reporting requirements, 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, and could impact the prices we charge our customers, 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 (and potential 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 a 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.

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

We are exposed to weather risk primarily in our utility business segment. A majority of our volume is driven from gas sales made to space heating residential and commercial customers during each winter heating season. Current utility rates are based on an assumption of average weather. Weather that is warmer than average typically results in lower gas sales. Sustained 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 so 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 another 10 percent 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.

Table of Contents

Customer conservation risk. Customers' conservation efforts 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.

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

Our gas distribution activities are subject to a variety of operating hazards and risks that cannot be completely avoided, such as leaks, accidents, mechanical problems, fires, explosions, earthquakes, floods, storms, landslides and other adverse weather conditions and hazards, which could cause substantial financial losses. In addition, our distribution facilities and equipment are subject to third party damage from construction activities and vandalism. These risks could result in loss of human life, significant damage to property, environmental pollution and disruption of our operations, which in turn could lead to financial losses. The occurrence of any of these events may not be fully covered by our insurance policies or be recoverable through rates, which could adversely affect our financial condition and results of operations.

Business continuity risk. We may be adversely impacted by 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 asset values, changing employee demographics and actuarial assumptions, which may have an adverse effect on our financial results.

We provide pension plans and postretirement healthcare benefits to eligible full-time employees. Our cost of providing such benefits is subject to changes in the market value of our pension assets, changing employee demographics, including longer life expectancies of beneficiaries, increases in healthcare costs, current and future legislative changes 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 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.

Table of Contents

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 our business strategy and serve our customers in our gas distribution business is dependent upon our continuing ability to attract and retain talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new employees as our aging employees retire. Without an appropriately skilled workforce, our ability to provide quality service to our customers and meet our regulatory requirements will be challenged and this could negatively impact our earnings. Additionally, a majority of our workers are represented by Office and Professional Employees International Union Local No.11 AFL-CIO (the Union) and are covered by a collective union agreement that will expire May 31, 2014. Disputes with the Union over terms and conditions of the collective union agreement could result in instability in our labor relationship and work stoppages that could impact the timely delivery of our product and services, which could strain relationships with customers and state regulators and cause a loss of revenues which could adversely affect our results of operations. The collective union agreement may also increase the cost of employing our workforce, affect our ability to continue offering market-based salaries and employee benefits, limit our flexibility in dealing with our workforce, and limit our ability to change work rules and practices and implement other efficiency-related improvements to successfully compete in today's challenging marketplace.

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

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

Additionally, changes in federal, state or local tax laws and their related regulations, or differing interpretation or enforcement of applicable law by a federal, state or local taxing authority, could 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. Unforeseen changes in laws, regulations or adverse judgments may negatively affect our financial condition and results of operations.

Business improvements risk. Our efforts to integrate, consolidate and streamline our operations have resulted in increased reliance on technology and third party vendors, 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; 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.

Table of Contents

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments.

ITEM 2. PROPERTIES

Utility Properties

Our natural gas distribution system consists of approximately 13,800 miles of distribution and transmission mains located in our service territory in Oregon and Washington. In addition, the distribution system includes service pipes, meters and regulators, and gas regulating and metering stations. The mains are located in municipal streets or alleys pursuant to valid franchise or occupation ordinances, in county roads or state highways pursuant to valid agreements or permits granted pursuant to statute, or on lands of others pursuant to valid easements obtained from the owners of such lands. We also hold all necessary permits for the crossing of the Willamette River and a number of smaller rivers by our mains.

We own service facilities in Portland, as well as various satellite service centers, garages, warehouses and other buildings necessary and useful in the conduct of our business. We lease office space in Portland for our corporate headquarters, which 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.

Gas Storage Properties

We hold interests in approximately 8,500 net acres of underground natural gas storage in Oregon and approximately 1,900 net acres of underground natural gas storage in California. We also hold interests in approximately 1,600 net acres of oil and gas leases in Oregon. We own rights to depleted gas reservoirs near Mist, Oregon, that are continuing to be developed and operated as underground gas storage facilities. We also hold an option to purchase future storage rights in certain other areas of the Mist gas field in Oregon, as well as in California related to the Gill Ranch storage project.

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 11, we have only routine nonmaterial litigation in the ordinary course of business.

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

There were no matters submitted to a vote of security holders, through the solicitation of proxies or otherwise, during the quarter ended December 31, 2009.

Table of Contents

PART II

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

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

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

	2009		2008	
Quarter Ended	High	Low	High	Low
March 31	$45.66	$37.71	$50.74	$41.07
June 30	46.07	39.58	48.22	43.08
September 30	46.00	41.12	55.23	43.66
December 31	46.47	40.83	53.71	36.61

The closing quotations for our common stock on December 31, 2009 and 2008 were $45.04 and $44.23, respectively.

(B) As of December 31, 2009, there were 7,418 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	2009	2008
February 15	$0.395	$0.375
May 15	0.395	0.375
August 15	0.395	0.375
November 15	0.415	0.395
Total per share	$1.600	$1.520

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

Table of Contents

(D) The following table provides information about purchases of our equity securities that are registered pursuant to Section 12 of the Securities Exchange Act of 1934 during the quarter ended December 31, 2009:

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
10/01/09 - 10/31/09	2,285	$43.19	-	-
11/01/09 - 11/30/09	24,416	$42.96	-	-
12/01/09 - 12/31/09	1,805	$45.00	-	-
Total	28,506	$43.11	2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2009, 25,126 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, 3,380 shares of our common stock were purchased on the open market during the quarter under equity-based programs. During the three months ended December 31, 2009, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) We have a share repurchase program for our common stock under which we purchase shares on the open market or through privately negotiated transactions. We have Board authorization through May 31, 2010 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. For the year ended December 31, 2009, no shares of our common stock were purchased pursuant to this program. Since the program's inception in 2000 we have repurchased 2.1 million shares of common stock at a total cost of $83.3 million.

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

	For the year ended December 31,				
Thousands, except per share amounts and ratio of earnings to fixed charges	2009	2008	2007	2006	2005
Utility operating revenues:					
Residential sales	$555,844	$566,840	$555,312	$536,468	$471,502
Commercial sales	292,697	298,943	298,800	290,666	250,287
Industrial - firm sales	41,407	46,579	54,567	66,986	64,507
Industrial - interruptible sales	62,116	68,978	74,876	93,107	100,740
Total gas sales revenues	952,064	981,340	983,555	987,227	887,036
Transportation	13,635	14,288	14,191	12,800	10,755
Regulatory adjustment for income taxes paid (1)	5,884	1,760	5,996	-	-
Other	21,166	21,784	12,228	161	2,862
Total gross utility operating revenues	992,749	1,019,172	1,015,970	1,000,188	900,653
Cost of gas sold	611,088	656,504	639,094	648,081	563,772
Revenue taxes	24,656	25,072	25,001	24,840	21,633
Utility net operating revenues	357,005	337,596	351,875	327,267	315,248
Non-utility net operating revenues	19,882	18,619	17,167	12,909	9,745
Net operating revenues	$376,887	$356,215	$369,042	$340,176	$324,993
Net income	$75,122	$69,525	$74,497	$63,415	$58,149
Average common shares outstanding:					
Basic	26,511	26,438	26,821	27,540	27,564
Diluted	26,576	26,594	26,995	27,657	27,621
Earnings per share of common stock:					
Basic	$2.83	$2.63	$2.78	$2.30	$2.11
Diluted	$2.83	$2.61	$2.76	$2.29	$2.11
Dividends paid per share of common stock	$1.60	$1.52	$1.44	$1.39	$1.32
Total assets - at end of period	$2,399,252	$2,378,152	$2,014,061	$1,956,856	$2,042,304
Long-term debt	$601,700	$512,000	$512,000	$517,000	$521,500
Ratio of earnings to fixed charges	3.86	3.76	3.92	3.40	3.32

(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.”)

Table of Contents

SELECTED FINANCIAL DATA (continued)

	For the year ended December 31,				
Thousands, except customer and gas cost per therm data	2009	2008	2007	2006	2005
Capitalization - at end of period					
Common stock equity	$660,105	$628,373	$594,751	$599,545	$586,931
Long-term debt	601,700	512,000	512,000	517,000	521,500
Total capitalization	$1,261,805	$1,140,373	$1,106,751	$1,116,545	$1,108,431
Gas sales and transportation deliveries (therms):					
Residential	412,867	428,787	398,960	382,665	371,538
Commercial	255,593	265,531	249,659	242,683	233,987
Industrial - firm	39,447	47,340	52,340	66,971	74,880
Industrial - interruptible	72,525	87,484	89,128	112,736	149,106
Total gas sales	780,432	829,142	790,087	805,055	829,511
Transportation	350,933	431,609	424,882	387,594	328,056
Total volumes delivered	1,131,365	1,260,751	1,214,969	1,192,649	1,157,567
Customers (average for period):					
Residential	601,989	594,481	580,346	564,700	545,163
Commercial	62,142	61,756	60,749	59,889	58,914
Industrial - firm	610	625	634	650	666
Industrial - interruptible	169	180	189	197	201
Transportation	158	136	128	99	78
Total customers	665,068	657,178	642,046	625,535	605,022
Customer statistics:					
Heat requirements:					
Actual degree days	4,383	4,576	4,374	4,089	4,178
Percent colder (warmer) than average	3 %	7 %	3 %	(4 %)	(2 %)
Average annual use per customer in therms:					
Residential	686	721	687	678	682
Commercial	4,113	4,300	4,110	4,052	3,972
Gas purchased cost per therm - net (cents)	71.96	86.56	75.00	75.37	71.42

Table of Contents

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

The following is management's assessment of Northwest Natural Gas Company's (NW Natural) financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated activities for the years ended December 31, 2009, 2008, and 2007. Unless otherwise indicated, references in this discussion to "Notes" are to the Notes to Consolidated Financial Statements in this report.

The consolidated financial statements principally consist of the accounts of NW Natural and its wholly-owned subsidiaries, NNG Financial Corporation (Financial Corporation) and Gill Ranch Storage, LLC (Gill Ranch), and an equity investment in a proposed natural gas pipeline. These accounts include our regulated local gas distribution business, our regulated gas storage business, and other regulated and non-regulated investments primarily in energy-related businesses. In this report, the term "utility" is used to describe our regulated local gas distribution segment, and the term "non-utility" is used to describe our gas storage segment (gas storage) as well as our other regulated and non-regulated investments and business activities (other segment) (see "2010 Outlook—Strategic Opportunities," below, and Note 2).

In addition to presenting results of operations and earnings amounts in total, certain measures are expressed in cents per share. These amounts reflect factors that directly impact earnings. We believe this per share information is useful because it enables readers to better understand the impact of these factors on earnings. All references in this section to earnings per share are on the basis of diluted shares (see Note 1). 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 2008 and 2009. 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 2009:

- Consolidated net income and earnings per share increased 8 percent to all time record highs of $75.1 million and $2.83 per share, respectively;
- Net operating revenues increased 6 percent to $376.9 million;
- Operations and maintenance expense increased 12 percent to $127.1 million;
- Cash flow from operations increased $205.6 million to $240.3 million;
- Permits were approved to proceed with the development at Gill Ranch, and construction began in January 2010;
- A new five-year contract was executed with our union employees, effective in July 2009; and
- The quarterly common stock dividend was increased 5 percent to 41.5 cents per share in the fourth quarter of 2009, making this the 54th 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 regulated 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 Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC). Factors critical to the success of our regulated 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; obtaining timely approval of reasonable rate increases; and with respect to future development of gas storage projects, being able to obtain financing to fund future development. Our existing gas storage business rates are approved by the Federal Energy Regulatory Commission (FERC) for interstate customers or the OPUC for intrastate customers. The Gill Ranch gas storage project currently under development is subject to regulation by the California Public Utilities Commission (CPUC) (see "2010 Outlook—Strategic Opportunities—Gas Storage Development," below).

Table of Contents

2010 Outlook

In 2010, we intend to remain focused on improving our core businesses, enhancing our strategic position, advancing business development projects related to our primary businesses, and strengthening our organizational effectiveness. The following is a brief summary of management's plans and objectives in these four areas. For a detailed discussion of these areas, see "Issues, Challenges and Performance Measures," and "Strategic Opportunities," below.

Business improvements. We continue to integrate, consolidate and streamline operations using recently implemented new technology improvements, 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 will respond to business challenges and opportunities that lie ahead, including finding innovative solutions to economic and environmental challenges as well as regulatory, business development and workforce challenges and opportunities.

Business development. In addition to exploring new growth opportunities, we intend to continue advancing key natural gas infrastructure investments during 2010, including our gas storage project in California and our gas transmission pipeline project in Oregon.

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

Issues, Challenges and Performance Measures

Economic weakness. Continued weakness in local and U.S. economies have resulted in reduced consumer demand and business spending. These conditions may continue to have a negative impact on our financial results, reflecting slower customer growth, reduced industrial margins, increased bad debt expense, and higher pension costs. Most recently, our annual customer growth rate slowed to 0.8 percent in 2009 compared to 1.6 percent in 2008. We expect our customer growth rate in 2010 to stabilize near 2009 levels, unless economic conditions deteriorate further. Despite challenging market conditions, we believe we are well positioned to continue adding customers due to 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. We entered the 2009-10 gas year, that began November 1, 2009, hedged at a targeted level of approximately 75 percent of our estimated gas purchase volumes for the gas contract year, and we believe we have sufficient contracted supplies to meet the needs of our core utility customers. In addition, we are currently hedged on gas prices for between 10 and 15 percent of our forecasted purchase volumes for the two gas contract years after October 31, 2010. We have Board authorization to hedge up to 100 percent of our gas supply requirements for the next gas contract year. Our Purchased Gas Adjustment (PGA) mechanism, along with gas price hedging strategies and gas supplies in storage, enables us to reduce earnings risk exposure to higher gas costs. In addition to hedging gas prices over the next three years, we are also evaluating and developing other gas acquisition strategies to potentially manage gas price volatility for customers beyond three years.

Environmental investigation and remediation 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 by the OPUC or WUTC, including environmental costs, and to seek recovery of these amounts in future rates to customers. However, before we can seek recovery from customers, we must 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 11.

Table of Contents

Climate change. We recognize that our businesses are likely to 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. While our CO2 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 is a fossil fuel with a 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.

Strategies and performance measures. In order to deal with the challenges affecting our business, we annually review and update our strategic plan to map our course over the next several years. Our plan includes strategies for: 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 natural gas 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 of 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; capital, 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 integrate, consolidate and streamline operations and support our employees with new technology tools.

In 2009, we completed the implementation of our new enterprise resource planning (ERP) system, which is designed to reduce the number of technology platforms and improve overall operating efficiencies by:

- integrating systems and data;
- automating control procedures and workflows; and
- improving management decision-making and financial reporting processes.

In 2009, we also completed our project to automate the reading of gas meters (AMR). Meters equipped with this new technology electronically transmit usage data to receiving devices located in our vehicles as they drive in the area, substantially reducing the labor costs associated with reading meters. The total capital cost of this project was approximately $25 million (see “Results of Operations—Regulatory Matters—Rate Mechanisms—AMR Deferral,” below).

In 2008 and 2009, we deployed an automated dispatching system, which provides integrated planning and scheduling with global positioning system capabilities to more effectively collect and distribute data. We will continue to deploy this new technology in the field during 2010.

In 2009, we announced a voluntary severance program to reduce staffing levels in response to work load declines related to slower customer growth and efficiency improvements. Severance programs and normal attrition resulted in reductions of full-time positions from 1,133 at December 31, 2008 to approximately 1,020 in early 2010. We incurred severance charges in the fourth quarter of approximately $1.5 million, which were partially offset by savings from vacated positions prior to the end of the year. We also expect some additional position reductions in 2010, but those reductions will most likely come from normal attrition.

Table of Contents

Technology investments, workforce reductions and the other initiatives discussed above are expected to facilitate process improvements, contribute to long-term operational efficiencies and reduce operating expenses throughout NW Natural.

Gas storage development. In 2007, we entered into a joint project agreement with Pacific Gas & Electric Company (PG&E) to develop an underground natural gas storage facility near Fresno, California. At that time, we formed a wholly-owned subsidiary, Gill Ranch, to plan and develop the project and to operate the facility. In July 2008, Gill Ranch filed an application with the CPUC for a Certificate of Public Convenience and Necessity (CPCN). In October 2009, we received an order from the CPUC approving our CPCN. Gill Ranch's provision of market-based rates for storage services in California will be subject to CPUC regulation including, but not limited to, service terms and conditions, tariff compliance, securities issuances, lien grants and sales of property. Our share of the total project development cost is estimated to be between $160 million and $180 million, representing 75 percent of the total cost of the initial development, which includes an estimated total 20 Bcf of gas storage capacity and approximately 27 miles of gas transmission pipeline. In January 2010, we began construction on the Gill Ranch facility. The initial development of the gas storage facility at Gill Ranch is currently targeted to be in-service by the end of the third quarter of 2010.

We are currently in the process of hiring key staff for our non-utility gas storage businesses. While our primary focus for growing the gas storage business is on the current development at Gill Ranch, we also plan to continue expanding our interstate storage facilities at Mist, Oregon. In 2009, we completed three-dimensional seismic surveys and initiated engineering work for a new 3 to 4 Bcf expansion at Mist. Pending successful marketing efforts, we expect to move forward with the project and would target a 2011 in-service date. Currently, our total cost estimates are between $45 million and $55 million for this expansion project. This estimated cost range includes the development of a second compression station and a pipeline gathering system that will also enable future storage expansions at Mist.

Pipeline diversification. Currently, we depend on a single bi-directional interstate pipeline to ship gas supplies to our utility distribution system. Palomar Gas Transmission, LLC, a wholly-owned subsidiary of Palomar Gas Holdings, LLC, (PGH), is seeking to build a new gas transmission pipeline that would provide a new interconnection with our utility distribution system. PGH is owned 50 percent by NW Natural and 50 percent by Gas Transmission Corporation (GTN), an indirect wholly-owned subsidiary of TransCanada Corporation. The proposed Palomar pipeline is a 217-mile natural gas transmission pipeline in Oregon designed to serve our utility and the growing markets in Oregon and other parts of the western United States. The Palomar pipeline would be regulated by the FERC. In December 2008, Palomar filed for a CPCN with the FERC.

The Palomar project includes an east and west segment. The east segment would extend approximately 111 miles west from an interconnection with GTN's existing interstate transmission mainline near Maupin, Oregon to an interconnection with NW Natural's gas distribution system near Molalla, Oregon. The west segment would then extend approximately 106 miles further west to other potential additional interconnections including a possible connection to one of the two liquefied natural gas (LNG) terminals proposed to be built on the Columbia River. The east segment would not only diversify NW Natural's gas delivery options and enhance the reliability of service to our utility customers by providing an alternate transportation path for gas purchases from different regions in western Canada and the U.S. Rocky Mountains, but also provide potential access to other shippers in the region. The west segment of Palomar would provide the region, as well as our utility customers with potential access to a new source of gas supply if an LNG terminal is built on the Columbia River. Palomar will continue to focus on permitting activities during 2010, and we believe the FERC will issue a draft Environmental Impact Statement during the first quarter of 2010. The date for when Palomar is expected to go into service will be impacted by the timing of our final FERC permit and the needs of shippers. In addition, the development of LNG terminals along the Columbia River may or may not proceed, which may affect the development of the west segment of Palomar. See "Financial Condition—Cash

Flows—Investing Activities," below for further discussion on the status of Palomar.

Table of Contents

Consolidated Earnings and Dividends

Net income was $75.1 million, or $2.83 per share, for the year ended December 31, 2009, compared to $69.5 million, or $2.61 per share, and $74.5 million, or $2.76 per share, for the years ended December 31, 2008 and 2007, respectively. Consolidated returns on average common equity for these three years were 11.7 percent, 11.4 percent and 12.5 percent, respectively.

2009 compared to 2008:

Factors contributing to increased earnings were:

- a $20.6 million increase in utility net operating revenue (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 margin from gas storage operations.

Partially offsetting the above factors were:

- a $13.7 million increase in operations and maintenance expense primarily due to higher 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.

2008 compared to 2007:

Factors contributing to decreased earnings were:

- a $5.5 million loss in utility margin from our regulatory share of gas cost increases in 2008 compared to a margin gain of $12.1 million in 2007 from gas cost decreases;
- a $4.2 million decrease in utility margin from a lower customer surcharge related to regulatory adjustments for income taxes paid;
- a $3.8 million increase in depreciation expense primarily due to increased utility plant in service;
- a $2.9 million decrease in margin due to a temporary mark-to-market gain in 2007; and
- a $1.6 million decrease in utility margin from industrial customers due to weaker economic conditions.

Partially offsetting the above factors were:

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

Dividends paid on our common stock were $1.60 per share in 2009, compared to $1.52 per share in 2008. In October 2009, the Board of Directors declared a quarterly dividend on our common stock of 41.5 cents per share, payable on November 13, 2009, increasing the indicated annual dividend rate to $1.66 per share.

Table of Contents

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 1.

Regulatory Accounting

We are regulated by the OPUC and WUTC, which establish our utility rates and rules governing utility services provided to customers, and, to a certain extent, set forth the accounting treatment for certain regulatory transactions. In general, we use the same accounting principles as non-regulated companies reporting under GAAP. However, 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.

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 regulated 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, 2009 and 2008 are recoverable or refundable through future customer rates. See Note 1, “Industry Regulation.”

Table of Contents

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, 2009 and 2008 were $71.2 million and $102.7 million, respectively. The decrease in accrued unbilled revenues at year-end 2009 was primarily due to lower volumes in 2009 reflecting warmer weather in late December 2009 and lower customer rates. If the estimated percentage of unbilled volume at December 31, 2009 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 $2.3 million, $0.1 million and $0.6 million, respectively.

Utility revenues may 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 over the life of the optimization contract for the guaranteed amount, and recognized as earned for amounts above the guaranteed amount.

Accounting for Derivative Instruments and Hedging Activities

Our gas acquisition policies set forth guidelines for using financial derivative instruments to support prudent risk management strategies. These policies specifically prohibit the use of derivatives for trading or speculative purposes. The accounting rules for determining whether a contract meets the definition of a derivative instrument or qualifies for hedge accounting treatment are complex. The contracts that meet the definition of a derivative instrument are recorded on our balance sheet at fair value. If certain regulatory conditions are met, then the fair value is recorded together with an offsetting entry to a regulatory asset or liability account pursuant to regulatory accounting (see Note 1, "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 1, "Derivatives" and "Industry Regulation"). Our derivative contracts outstanding at December 31, 2009 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, 2009 and 2008, see Note 10.

Commodity-based derivative contracts entered into by the utility after our annual PGA filing for the current gas contract period are subject to a regulatory incentive sharing mechanism in Oregon (see "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," below). The portion not deferred to a regulatory account pursuant to that sharing agreement is recognized either in current income for contracts not

qualifying for hedge accounting or in other comprehensive income for contracts qualifying for hedge accounting.

Derivative hedge contracts are subject to a hedge effectiveness test to determine the financial statement treatment of each specific derivative. As of December 31, 2009, 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.

Table of Contents

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

Thousands	2009	2008	2007
Net gain (loss) on commodity-price swaps - utility	$(172,089)	$34,256	$(41,954)
Net gain (loss) on commodity-price options - utility	(5,809)	1,527	(662)
Net gain (loss) on interest rate swap - utility	(10,096)	-	-
Subtotal on commodity - utility	(187,994)	35,783	(42,616)
Net gain (loss) on foreign currency forward purchases - utility	88	(728)	662
Total realized net gain (loss)	$(187,906)	$35,055	$(41,954)

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 other comprehensive income, but are recorded as regulatory liabilities or regulatory assets, and are offset by a corresponding balance in non-trading derivative assets or liabilities (see Note 10).

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. Only the two qualified defined benefit pension plans have plan assets, which are held in a qualified trust to fund retirement benefits. Effective January 1, 2007 and 2010, the qualified defined benefit retirement plans for non-union employees and for union employees, respectively, were closed to new participants. Instead, non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, 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.

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 7). 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 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 1, “Industry Regulation”).

Table of Contents

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, 2009 measurement date, we reviewed and updated:

- our pension and postretirement weighted-average discount rate assumptions from 6.60 percent to 6.01 percent and from 7.12 percent to 5.78 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 changed from a range of 3.5 to 5.0 percent to 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.

At December 31, 2009, our net pension liability (benefit obligations less market value of plan assets) for the two qualified defined benefit plans decreased by $10.5 million compared to 2008. Better than expected investment performance plus a cash contribution of $25 million more than offset the $19.0 million increase in benefit obligations due to lower discount rates and $4.2 million increase due to updating other assumptions, thereby resulting in the net decrease to our unfunded pension liability. The liability for non-qualified plans increased $3.1 million and the liability for other postretirement benefits increased $1.8 million in 2009.

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, 2009, 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 15.79 percent, 2.23 percent, 2.96 percent and 10.29 percent, respectively.

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

Thousands, except percent	Change in Assumption	Impact on 2009 Retirement Benefit Costs	Impact on Retirement Benefit Obligations at Dec. 31, 2009
Discount rate:	(0.25 %)		
Qualified defined benefit plans		$ 862	$ 8,604
Non-qualified plans		7	3,212
Other postretirement benefits		100	558
Expected long-term return on plan assets:	(0.25 %)		
Qualified defined benefit plans		550	N/A

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.

Table of Contents

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, 2009 and 2008, our net long-term deferred tax liability totaled $300.9 million and $257.8 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, 2009, 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, 2009 and 2008, we had regulatory assets representing differences between book and tax basis related to pre-1981 property of $76.2 million and $69.9 million, respectively, and recorded an offsetting deferred tax liability (see Note 1, "Income Tax Expense"). We received authorization from the OPUC and WUTC in 2008 to accelerate the recovery of these pre-1981 regulatory assets through future utility rates (see "Regulatory Accounting," above, and Notes 1 and 8).

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, 2009, 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 returns is expected during 2010.

Interest and penalties, if any, related to any future income tax deficiencies 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 defense costs when such costs are probable of being incurred and are reasonably estimable, and related disclosures are updated when new information becomes available. Estimating probable losses requires an analysis of uncertainties that often depend upon judgments about potential actions by third parties. Accruals for loss contingencies are recorded based on an analysis of potential results. When information is sufficient to estimate only a range of potential liabilities, and no point within the range is more likely than any other, we recognize an accrued liability at the low end of the range and disclose the range (see "Contingent Liabilities," below). It is possible, however, that the range of potential liabilities could be significantly different than amounts

currently accrued and disclosed, with the result that our financial condition and results of operations could be materially affected by changes in the assumptions or estimates related to these contingencies.

With respect to environmental liabilities and related costs we develop estimates based on a review of information available from recently completed studies and negotiations involving several sites. Using sampling data, feasibility studies, existing technology and enacted laws and regulations, we estimate that the total future expenditures for environmental investigation, monitoring and remediation are $65.3 million as of December 31, 2009. It is our policy to accrue the full amount of such liability when information is sufficient to reasonably estimate the amount of probable liability. When information is not available to reasonably estimate the probable liability, or when only the range of probable liabilities can be estimated and no amount within the range is more likely than another, then it is our policy to accrue at the lower end of the range. Accordingly, due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot be reasonably estimated. Therefore, we have recorded the liabilities at an amount that reflects the most likely estimate or the low end of the range.

Table of Contents

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 11).

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 2009, approximately 90 percent of our utility gas volumes were delivered to, and utility operating revenues were derived from, Oregon customers and the balance from Washington customers. Future earnings and cash flows from utility operations will be determined largely by the Oregon and Washington economies in general, and by the pace of growth in the residential and commercial markets in particular, and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery for our utility gas costs, operating and maintenance costs and investments made in utility plant.

General Rate Cases

Oregon. In our most recent general rate increase in Oregon, which was effective 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 1, 2011, subject to certain exceptions. Under the agreement, we would be allowed to file a general rate case if an extraordinary event occurs or significant investments are required on behalf of our customers and we are unable to reach agreement regarding alternative forms of cost recovery outside of a general rate case. These exceptions might include additional investments in our pipeline integrity management program. This agreement does not impact our ability to file annual rate adjustments to reflect changes in gas purchase costs under our PGA mechanism or our ability to collect or refund prior year's gas cost deferrals. See "Rate Mechanisms—Purchased Gas Adjustment," below.

Washington. In December 2008, an all-party stipulated agreement regarding our Washington general rate case was approved by the WUTC. As part of the stipulation, the WUTC authorized rates to our customers based on a ROE of 10.1 percent, which is included as part of an overall rate of return on total invested capital of 8.4 percent. These new customer rates went into effect on January 1, 2009. Under these rates, our annual revenue requirements increased by approximately $2.7 million, or 3 percent. We are reviewing recent decisions regarding decoupling mechanisms in Washington and considering whether to request approval for a decoupling mechanism.

Federal. We are required under our Mist interstate storage certificate authority and rate approval orders to file every three years either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for our interstate storage services. We filed a cost and revenue study and an associated petition for rate approval in April 2008. As a result of that proceeding, the current maximum cost-based rates for our interstate gas storage services were approved by FERC in August 2008, with our maximum rates unchanged from the levels approved by FERC in 2005. The maximum cost-based rates are designed to reflect updated costs related to the further development of the Mist gas storage facility from 2005 to 2008. Additionally, we made a filing 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 to match the depreciation rates for the same assets that were recently adjusted under state regulation. We did not file to make any changes to the previously approved maximum rates. 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, 2011.

Table of Contents

California. To date, we have not filed any rate cases or storage service tariffs with the CPUC. Later in 2010, we expect to file a storage service tariff with the CPUC with respect to Gill Ranch.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are established each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases, including gas storage, gas purchases hedged with financial derivatives, interstate pipeline demand charges, the application of temporary rate adjustments to amortize balances in deferred regulatory accounts and the removal of temporary rate adjustments effective for the previous year.

In October 2009, the OPUC and WUTC approved rate changes effective on November 1, 2009 under our PGA mechanisms. The effect of the rate changes was to decrease the average monthly bills of Oregon residential customers by 18 percent, partially offset by an increase in the public purpose charge, which resulted in a net decrease of 16 percent. The average monthly bills of Washington residential customers decreased by 22 percent.

Under the current Oregon PGA incentive sharing mechanism, we are required to select by August 1 of each year either an 80 percent deferral or 90 percent deferral of higher or lower actual gas costs compared to PGA prices such that the impact on current earnings from the gas cost incentive sharing is either 20 percent or 10 percent, respectively. In addition to the gas cost incentive sharing mechanism, we are also subject to an annual earnings review to determine if the utility is earning over an allowed threshold. If utility earnings exceed a specific earnings threshold level, then 33 percent of the amount above the threshold 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 80 percent deferral option for the 2008-2009 PGA year. In August 2009, we selected 90 percent deferral for the 2009-2010 PGA year. The earnings threshold is subject to adjustment up or down depending on movements in long-term interest rates. In 2009 and 2008, the earnings threshold after adjustment for long-term interest rates was 11.5 percent and 13.1 percent, respectively. No amounts were required to be refunded to customers as a result of the 2008 utility earnings review, and we do not expect that any amounts will be required to be refunded to customers as a result of the 2009 earnings review, which will be approved by the OPUC during the second quarter of 2010.

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

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

The Oregon conservation tariff includes two components: (1) a price elasticity adjustment, which adjusts rates annually for increases or decreases from expected customer volumes due to annual changes in commodity costs or periodic changes in our general rates; and (2) a conservation adjustment calculated on a monthly basis to account for the difference between actual and expected 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 "Results of Operations—Business Segments - Utility Operations," below.

Table of Contents

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

Weather Normalization. In Oregon, the OPUC approved our use of a weather normalization mechanism through October 2012. This mechanism is designed to help stabilize the collection of fixed costs by adjusting residential and commercial customer billings based on temperature variances from average weather, with rate decreases when the weather is colder than average and rate increases when the weather is warmer than average. The mechanism is applied to our residential and commercial customers' bills between December 1 and May 15 of each heating season. The mechanism adjusts the margin component of customers' rates to reflect average weather, which uses the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers (see "Business Segments - Utility Operations," below). We do not have a weather normalization mechanism approved for our Washington customers, which account for about 10 percent of our utility revenues.

Regulatory and Insurance Recovery for Environmental Costs. The OPUC has authorized us to defer environmental costs associated with certain named sites and 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. These authorizations have been extended through January 2010. We have requested another extension through January 2011, and that request is currently pending. See Note 11.

Industrial Tariffs. The OPUC and WUTC have approved tariffs covering service to our major industrial customers, including terms which are intended to give us certainty in the level of gas supplies we will 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 cost of gas 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 ending September 30, and recover the revenue requirement associated with the costs, subject to audit, through rate changes effective with the annual PGA in Oregon. The PHMSA also had proposed a distribution integrity management program. In February 2009, the OPUC approved a stipulated agreement to create a new, consolidated system integrity program (SIP). The SIP integrates the existing transmission pipeline and proposed 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 and other interested parties.

The SIP allows recovery of costs incurred, as discussed above, 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. We do not have any special accounting or rate treatment for SIP costs incurred in the state of Washington.

AMR Deferral. In 2009, we completed a project to automate the reading of our Oregon customers' gas meters. The capital cost of this AMR project was approximately $25 million. In February 2010, the OPUC approved a stipulation that allows us to defer the revenue requirement associated with the AMR project and amortize that deferral subject to

an annual earnings test. We are permitted to recover the deferral amount as long as our ROE during the earnings review period does not exceed our authorized ROE. Earnings or losses from our PGA gas cost incentive sharing mechanism are not included for purposes of this earnings test. Recovery of any deferred amounts will begin in November 2010 as part of our annual PGA rate adjustment.

Table of Contents

Depreciation Study. 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 (see "Consolidated Operations—Depreciation and Amortization," below). 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.

Customer Refunds for Gas Cost Incentive Sharing. For the period between November 1, 2008 and March 31, 2009, our actual gas costs were significantly lower than the gas costs embedded in customer rates. As a result, 80 percent of the gas cost savings attributed to Oregon and 100 percent of the savings attributed to Washington were recorded to a regulatory account for refund to customers (see “Purchased Gas Adjustment,” above). Ordinarily, these refunds would be included in customer rates in the next year’s PGA filing, but in 2009 we received special regulatory approval to refund the accumulated gas cost savings early to our Oregon and Washington customers. In June and July 2009, we refunded a total of $31.5 million to our Oregon customers and $4.3 million to our Washington customers through billing credits.

Pension Deferral. We are currently subject to a regulatory deferral order from the OPUC whereby we must refund cost savings to customers when our annual pension expense is below the amount set for rate recovery in our last general rate case. However, we are currently not authorized to defer and recover any cost increases from customers when our annual pension expense is above the amount set in rates. For 2010, our annual pension expense is expected to be significantly above the amount set in rates, and we may seek some form of regulatory relief for pension expenses between now and our next general rate case.

Business Segments - Utility Operations

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

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 over last year 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 compared to 2008, primarily due to the cost of gas savings in 2009.

Our weather normalization mechanism reduced residential and commercial margin 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.

2008 compared to 2007:

Our utility segment in 2008 earned $58.7 million, or $2.21 per share, compared to $64.9 million, or $2.41 per share in 2007. This decrease is primarily due to a decrease in utility margin of $14.3 million or 4 percent even though margins from residential and commercial customers contributed an additional $7.1 million in 2008, including the effects of the weather normalization and decoupling mechanisms while margin from industrial customers declined by $1.6 million. Total utility volumes sold and delivered in 2008 increased by 4 percent over 2007 due to colder weather and 1.6 percent customer growth. The major factors contributing to the decline in utility margin were the $17.6 million decrease in our regulatory incentive sharing from higher gas costs, a $4.2 million decrease in the regulatory adjustments for income taxes paid and a $1.6 million decrease in margin from industrial customers due to weak economic conditions.

Table of Contents

Our weather normalization mechanism offset residential and commercial margin gains by $15.3 million for the year ended December 31, 2008 based on weather that was 7 percent colder than average, compared to an offset of $2.5 million for the year ended December 31, 2007, based on weather that was 3 percent colder than average in 2007. Our decoupling mechanism recovered $4.9 million of residential and commercial margin losses in 2008, after adjusting for expected price elasticity impacts from higher PGA prices effective November 1, 2007, compared to a margin recovery of $0.5 million in 2008.

The following table summarizes the composition of gas utility volumes and revenues for the years ended December 31, 2009, 2008 and 2007:

Thousands except degree day and customer data	2009	2008	2007	Favorable/(Unfavorable) 2009 vs. 2008	2008 vs. 2007
Utility volumes - therms:					
Residential sales	412,867	428,787	398,960	(15,920)	29,827
Commercial sales	255,593	265,531	249,659	(9,938)	15,872
Industrial - firm sales	39,447	47,340	52,340	(7,893)	(5,000)
Industrial - firm transportation	124,218	184,832	161,790	(60,614)	23,042
Industrial - interruptible sales	72,525	87,484	89,128	(14,959)	(1,644)
Industrial - interruptible transportation	226,715	246,777	263,092	(20,062)	(16,315)
Total utility volumes sold and delivered	1,131,365	1,260,751	1,214,969	(129,386)	45,782
Utility operating revenues - dollars:					
Residential sales	$555,844	$566,840	$555,312	$(10,996)	$11,528
Commercial sales	292,697	298,943	298,800		