NWN 10-K 12/31/2007

Section 1: 10-K (FORM 10-K)

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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, 2007

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

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

Oregon (State or other jurisdiction of incorporation or organization)	**93-0256722** (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. [ ]

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of "accelerated filer," "large accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

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

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

As of June 29, 2007, the registrant had 26,815,203 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 $1,226,580,437.

At February 25, 2008, 26,408,248 shares of the registrant's Common Stock (the only class of Common Stock) were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

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

Portions of the Proxy Statement of Company, to be filed in connection with the 2008 Annual Meeting of Shareholders, are incorporated by reference in Part III.

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GLOSSARY OF TERMS

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

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

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

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

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

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

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

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

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

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

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

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

Interruptible service: natural gas service offered to customers (usually large commercial or industrial 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.

Open Season: A period of time during which prospective customers express binding or non-binding interest in pipeline or gas storage services.

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

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

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

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

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

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

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

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

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

NORTHWEST NATURAL GAS COMPANY
PART I

ITEM 1. BUSINESS

General

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

Business Segments

Local Gas Distribution

We are principally engaged in the distribution of natural gas in Oregon and southwest Washington. In this report our principal business segment is referred to as local gas distribution or utility. Local gas distribution involves purchasing gas from producers, transporting the gas over interstate pipelines from the supply basins to our service territory, and reselling the gas to customers at rates and terms approved by the Oregon Public Utility Commission (OPUC) or by the Washington Utilities and Transportation Commission (WUTC). Gas distribution also includes transporting gas owned by large customers from the interstate pipeline connection, or city gate, to the customers' facilities for a fee, also approved by the OPUC or WUTC. Approximately 96 percent of our consolidated assets and 87 percent of our consolidated net income in 2007 are related to the local gas distribution segment. The OPUC has allocated to us as our exclusive service area a major portion of western Oregon, including the Portland metropolitan area, most of the Willamette Valley and the coastal area from Astoria to Coos Bay. We also hold certificates from the WUTC granting us exclusive rights to serve portions of three southern Washington counties bordering the Columbia River. Gas service is provided in 123 cities and neighboring communities in 15 Oregon counties, as well as in 14 cities and neighboring communities in three Washington counties. The city of Portland is the principal retail and manufacturing center in the Columbia River Basin, and is a major port for trade with Asia.

At year-end 2007, we had approximately 590,000 residential customers, 61,000 commercial customers and 900 industrial sales customers. Approximately 90 percent of our customers are located in Oregon and 10 percent are in Washington. Industries served include: pulp, paper and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery and textiles; the manufacture of asphalt, concrete and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation. No individual customer or industry accounts for a significant portion of our industrial revenues.

Gas Storage

The gas storage business segment includes NW Natural's underground natural gas storage services to interstate and large intrastate customers using NW Natural's storage and related transportation capacity that is in excess of core utility customer requirements. Additionally, an independent energy marketing company provides asset optimization services to the utility under a contractual arrangement, the results of which are included in this business segment. Approximately 3 percent of our consolidated assets and 12 percent of consolidated net income in 2007 are related to the gas storage business segment. For each of the years ended December 31, 2007, 2006, and 2005, this business segment derived a majority of its revenues from multi-year contracts with less than 10 customers. The total working gas capacity of the Mist underground gas storage facility has been increased from 14 Bcf to around 16 Bcf to reflect an expansion in certain reservoir pools. Of this capacity, the gas storage business has access to about 7 Bcf of capacity while the utility has access to the remaining 9 Bcf.

Pre-tax income from gas storage and third-party optimization activities 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 deferred to a regulatory account for rate credits 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.

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

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

Third Party Optimization. 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. See Part II, Item 7., "Results of Operations—Business Segments Other than Local Gas Distribution—Gas Storage."

Other

We have other investments, including assets in NNG Financial Corporation (Financial Corporation) (see "Subsidiaries," below), a Boeing 737-300 aircraft under lease to Continental Airlines but currently held for sale, and investments in development projects such as Gill Ranch and Palomar Pipeline (see "Subsidiaries," below). Less than 1 percent of our consolidated assets and about 1 percent of 2007 consolidated net income are related to activities in the "Other" business segment.

Subsidiaries

Financial Corporation

Financial Corporation, a wholly-owned subsidiary incorporated in Oregon, holds non-utility financial investments. Financial Corporation has one active, wholly-owned subsidiary, KB Pipeline Company (KB Pipeline), which owns a 10 percent interest in an 18-mile interstate natural gas pipeline.

In October 2007, Financial Corporation's limited partnership investments in two wind power electric generation projects in California were sold. In addition, in December 2007, one of Financial Corporation's two low-income housing project investments reached the end of its contract period and the partnership investment was disposed of pursuant to the original terms of the agreement.

Gill Ranch

In September 2007, we announced a joint project with Pacific Gas & Electric Company (PG&E) to develop a new underground natural gas storage facility at Gill Ranch near Fresno, California. We formed a wholly-owned subsidiary of NW Natural to develop and operate the facility. Gill Ranch Storage, LLC, will initially own 75 percent of the project, and PG&E will own 25 percent. The new storage facility is expected to provide approximately 20 Bcf of underground gas storage capacity, and will include 25 miles of transmission pipeline, when the initial phase is completed. We estimate our share of the total cost for the initial phase of development to be between $150 million and $160 million over the next three years, which represents 75 percent of the estimated project cost. We conducted an open season to gauge interest in the storage facility from October 2007 to December 2007, and the results indicated a strong level of interest in gas storage at Gill Ranch from potential storage customers. We expect to file an application with the California Public Utilities Commission (CPUC) for a Certificate of Public Convenience and Necessity in mid-2008 and, if granted, Gill Ranch will be subject to CPUC regulation with respect to rates and various regulatory approvals, including but not limited to securities issuance, lien grants and sales of property. We expect the initial phase of Gill Ranch to be in-service by late 2010.

Gas Supply, Storage and Transportation Capacity

General

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

Gas Acquisition Strategy

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

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

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

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

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

Regional Supply Basin

Region	2007 Actual	2007-2012 Target
Alberta	41%	45%
British Columbia	27%	30%
U.S. Rockies	32%	25%
Mist gas field	<1%	<1%
Total	100%	100%

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

We typically enter into gas purchase contracts for:

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

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

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

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

- negotiating fixed prices directly with gas suppliers;
- negotiating financial instruments that exchange the floating price in a physical supply contract for a fixed price (referred to as price swaps);

- negotiating financial instruments that set a ceiling or floor price, or both, on a floating price contract (referred to as calls, puts, and collars); and
- buying gas and injecting it into storage. See "Cost of Gas," below.

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

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

- the use of purchased gas adjustment (PGA) mechanisms approved by the OPUC and WUTC (see Part II, Item 7., "Results of Operations—Regulation and Rates—Rate Mechanisms," below);
- aligning customer and shareholder interests through incentive sharing mechanisms, such as the PGA and asset optimization mechanisms; and
- periodic review of regulatory deferrals with state regulatory commissions and key customer groups.

Cost of Gas

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

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

Transportation cost. Pipeline transportation rates charged by our pipeline suppliers had been stable until recently when two of the five major pipelines used by NW Natural filed with the FERC for significant rate increases in 2006, which were implemented in 2007. Pipeline transportation rate increases are generally recoverable through our state-approved PGA mechanisms.

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

Managing the Cost of Gas

We manage natural gas commodity price risk through an active hedging program in which we enter into either fixed price physical supply contracts or fixed price financial derivatives contracts. The financial contracts make up a majority of our commodity price hedging activity and these contracts are with a variety of investment-grade credit counterparties, typically with credit ratings of AA- or higher. See Part II, Item 7A., "Quantitative and Qualitative Disclosures About Market Risk—Credit Risk—Credit exposure to financial derivative counterparties." Under this program, we enter into commodity swaps, puts, calls or collars for the coming year and up to three years into the future. Gains or losses from financial commodity hedge contracts are treated as reductions or increases to the cost of gas. The intended effect of this program is to lock in prices for a majority of our gas supply portfolio for the following gas contract year, including at least 50 percent of the expected heating season purchases, based on the market prices and forecasted purchase requirements prevailing at the time the financial agreements are entered into.

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

Source of Supply—Design Day Sendout

The effectiveness of our gas supply program ultimately rests on whether we provide reliable service at a reasonable cost to our core utility customers. To assure reliability, we base our plans on being able to meet the supply needs on the coldest weather experienced over the last 20 years in our service territory. We start with the coldest overall heating season and then modify it to include the coldest weather day over that same 20-year period. This coldest "design day" is the maximum anticipated demand on the natural gas distribution system during a 24-hour period, which currently assumes weather at an average temperature of 12 degrees Fahrenheit. We assume that all interruptible customers will be curtailed on the design day. Our projected sources of delivery for design day firm utility customer sendout total approximately 8.86 million therms. We are currently capable of meeting 63 percent of our firm customer design day requirements with storage and peaking supply sources located within or adjacent to our service territory. Optimal utilization of storage and peaking facilities on our design day reduces the dependency on firm 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. 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 planning (IRP) process (see "Regulation and Rates—Integrated Resource Plan," below).

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The following table shows the sources of supply that are projected to be used to satisfy the design day sendout for the 2007-2008 winter heating season:

Projected Sources of Supply for Design Day Sendout

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

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

Core Utility Market Basic Supply

We purchase gas for our core utility customers from a variety of suppliers located in the western United States and Canada. As shown above, about 65 to 70 percent of our supply comes from Canada, with the balance coming primarily from the U.S. Rocky Mountain region. At January 1, 2008, we had 23 firm contracts with 14 suppliers and remaining terms ranging from three months to eight years, which provide for a maximum of 2.2 million therms of firm gas per day during the peak winter heating season and 1.2 million therms per day during the remainder of the year. These contracts have a variety of pricing structures and purchase obligations. During 2007, we purchased 809 million therms of gas under the following contract durations:

Contract Duration (primary terms)	Percent of Purchases
Long-term (one year or longer)	53%
Short-term (more than one month, less than a year)	11%
Spot (one month or less)	36%
Total	100%

We regularly renew or replace our expiring long-term gas supply contracts with new agreements from a variety of existing and new suppliers. Aside from the optimization of our core utility gas supplies by the independent energy marketing company (see "Gas Acquisition Strategy—Asset Optimization," above), three suppliers each provide between 11.1 percent and 12.5 percent of our average daily contract volumes. Firm year-round supply contracts have remaining terms ranging from one to eight years. All term gas supply contracts use price formulas tied to monthly index prices, primarily at the NIT trading point in Alberta. We hedge a majority of these contracts each year using financial instruments as part of our gas purchasing strategy (see "Managing the Cost of Gas," above).

In addition to the year-round contracts, we continue to contract in advance for firm gas supplies to be delivered only during the winter heating season primarily under short-term contracts. During 2007, new short-term purchase agreements were entered into with six suppliers. These agreements have a variety of pricing structures and provide for a total of up to 990,000 therms per day during the 2007-2008 heating season. We intend to enter into new purchase agreements in 2008 for equivalent volumes of gas with our existing or other similar suppliers, as needed, to replace contracts that will expire during 2008.

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

We continue to purchase gas from a non-affiliated producer in the Mist gas field in Oregon. The production area is situated near our underground gas storage facility. The price for this gas is tied to our weighted average cost of gas. Current production is approximately 10,000 therms per day from about 17 wells, supplying less than 1 percent of our total annual purchase requirements. Production from these wells varies as existing wells are depleted and new wells are drilled.

Core Utility Market Peaking Supply and Storage

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

Underground storage. We provide daily and seasonal peaking from our underground gas storage facility in the Mist gas storage field. Including the latest expansions in 2007, this facility has a maximum daily deliverability of 5.1 million therms and a total working gas capacity of about 16 Bcf. In September 2004, we completed our South Mist pipeline extension project, which is a utility transmission pipeline from our Mist gas storage field to growing portions of our distribution service area. Also in 2004, a total of 400,000 therms per day of Mist storage capacity, which had been available for the non-utility gas storage business, was recalled and committed to use for core utility customers. This was the first instance of returning capacity that had been developed in advance of core utility customers' needs for interstate gas storage services under the regulatory agreement with the OPUC. Under this agreement, storage capacity is recalled as needed and added to utility rate base, at our original cost less accumulated depreciation, with a corresponding rate increase to customers to reflect the cost of service. No additional recalls of Mist capacity were required in 2005, 2006 or 2007. The core utility market now has 2.3 million therms per day of deliverability and approximately 9 Bcf of working gas committed from the Mist storage facility. As storage capacity is recalled to serve core utility customers, new storage capacity may be developed.

We also have contracts with Northwest Pipeline Corporation (Northwest Pipeline) for firm gas storage services from an underground storage facility at Jackson Prairie near Chehalis, Washington, and an LNG facility at Plymouth, Washington. Together, these 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.

LNG. We own and operate two LNG storage facilities in our service territory that liquefy gas during the summer months for storage until 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. We also have contracts with one electric generator and two industrial customers that together provide an additional 52,000 therms per day of year-round upstream capacity, plus 450,000 therms per day of recallable capacity and supply. Two of these three contracts renew from year to year, while the third will expire in 2010.

Transportation

Dependence on a Single Transportation Pipeline. Our distribution system is directly connected to a single interstate pipeline, Northwest Pipeline. Although we are dependent on a single pipeline, the pipeline is bi-directional as it transports gas into the Portland metropolitan market from two directions: (1) the north, which brings supplies from British Columbia and Alberta supply basins; and (2) the east, which brings supplies from Alberta as well as the Rocky Mountain supply basins. The need for pipeline transportation diversity has been underscored by past Northwest Pipeline ruptures and the resulting federal order in 2003 that required Northwest Pipeline to replace its 26-inch mainline from the Canadian border to our service territory. That replacement project was completed by Northwest Pipeline in November 2006. We are pursuing options to further diversify our pipeline transportation paths. Specifically, we are currently evaluating a potential pipeline project that would connect TransCanada Pipelines Limited's (TransCanada) Gas Transmission Northwest (GTN) interstate transmission line to our gas distribution system. In August 2007, we entered into an agreement with GTN for the purpose of jointly developing and owning this proposed pipeline. If constructed, this pipeline would provide an alternate transportation path for gas purchases in Alberta that currently move through the Northwest Pipeline system (See Part II, Item 7., "2008 Outlook—Strategic Opportunities—Pipeline Diversity").

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

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

Our second largest transportation agreement with Northwest Pipeline extends through 2011. It provides 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 and two upstream pipelines in Canada, which match the amount of Northwest Pipeline capacity northward into Alberta, Canada.

We also have an agreement with Northwest Pipeline that previously extended into 2009 for approximately 350,000 therms per day of firm transportation capacity from the U.S. Rocky Mountain region. In February 2008, we extended the term of this contract through 2044. Also in February 2008, we executed an agreement with a third party to take assignment of their firm gas supply transportation contract starting no earlier than 2012 and no later than 2017, with a term extending through 2046. This contract consists of 120,000 therms per day on Northwest Pipeline from the U.S. Rocky Mountain region.

In addition, we have firm long-term pipeline transportation contracts with two other major transporters. A contract with Spectra Energy Corporation (formerly Westcoast Energy, Inc.) extends through October 2014 and provides approximately 600,000 therms per day of firm gas transportation from Station 2 in northern British Columbia to the Huntingdon/Sumas connection with Northwest

Pipeline at the U.S./Canadian border. A contract with Terasen Gas extends through October 2020 and provides approximately 470,000 therms per day of firm gas transportation from southeastern British Columbia to the same Huntingdon/Sumas connection with Northwest Pipeline. Our capacity with Terasen Gas is matched with companion contracts for pipeline capacity on the TransCanada BC system and NOVA system in British Columbia and Alberta, allowing purchases to be made from the gas fields of Alberta, Canada.

Regulation and Rates

We provide local distribution gas utility service in Oregon and Washington and, accordingly, we are subject to state regulation with respect to, among other matters, rates, systems of accounts and issuance of securities by the OPUC and the WUTC. Local distribution service in Oregon represents about 91 percent of the utility's revenues, while Washington represents the remaining 9 percent (see Part II, Item 8., Note 1).

We periodically file general rate case and rate tariff requests with the OPUC and WUTC to change the rates we charge our customers. 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 the future, we may be subject to regulation in other states resulting from our strategic investments. For further information, see Part II, Item 7., "Results of Operations—Regulatory Matters," below.

Integrated Resource Plan

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

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

Although the OPUC's order acknowledging the integrated resource plan does not constitute ratemaking approval of any specific resource acquisition or expenditure, the OPUC generally indicates that it would give considerable weight in prudency reviews to utility actions that are consistent with acknowledged plans. Elements of our current integrated resource plan demonstrate that the continued development of the Mist underground gas storage facility is the least-cost option for serving customer growth. We filed a draft IRP with the WUTC in the first quarter of 2007, and we expect to file a draft IRP with the OPUC by the end of the first quarter of 2008.

Additions to Infrastructure

We expect a high level of capital expenditures for additions to infrastructure over the next five years, reflecting projected customer growth, technology, distribution system replacement, improvement and reinforcement projects and the development of additional gas storage facilities. In 2008, utility capital expenditures are estimated to be between $90 and $100 million, and business development investments could amount to between $15 and $25 million. For the years 2008-2012, capital expenditures for the utility are estimated at between $500 and $600 million, while business development investments will depend largely on decisions about potential opportunities in storage and pipeline development projects. Despite a slower annual growth rate than in past years, our growth rate during 2007 continued to be above the national average for gas utilities.

Pipeline Safety

The Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (2006 Act) was signed into law in December 2006. The 2006 Act mandates certain standards related to our distribution lines, including the development of an integrity management program for those distribution pipelines. Distribution pipeline safety rules required by the 2006 Act are expected to be final in 2009.

The Pipeline Safety Improvement Act of 2002 (2002 Act) and related regulations require gas transmission pipeline operators to identify lines located in High Consequence Areas (HCAs) and develop integrity management programs to periodically inspect the pipelines and make repairs or replacements as necessary to ensure the ongoing safety of the pipelines. The legislation and related pipeline safety regulations require us to complete inspection of 50 percent of the highest risk pipelines located in our HCAs within the first five years, and the remaining covered pipelines within 10 years, of the date of enactment. We are also required to re-inspect the covered pipelines every seven years from the date of the previous inspection for the life of the pipelines. We continued to achieve our milestones, completing the required inspection of the top 50 percent highest risk transmission pipelines in 2007. We are currently on track to meet the next milestone to complete the inspection of all transmission pipelines in HCAs by December 2012.

In 2005, we assumed responsibilities as operator of an approximately 60-mile pipeline that transports gas from Northwest Pipeline to Coos County, Oregon. The pipeline is owned by Coos County, and we have an agreement to operate the pipeline and related lateral pipelines that continues yearly until terminated by either party. The pipeline safety requirements of the 2002 Act apply to us as operator of that pipeline.

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

Competition and Marketing

Competition with Other Energy Products

We have no direct competition in our service area from other natural gas distributors. However, for residential customers, 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 gas-to-gas competition from third-party sellers of natural gas commodity.

Competition among these forms of energy is based on price, reliability, efficiency and performance, which can change from year-to-year based on market conditions, technology and legislative policy.

Residential and Commercial Markets

The relatively low market saturation of natural gas in residential single-family dwellings in our service territory, estimated at approximately 50 percent, together with the price advantage of natural gas compared with electricity in most areas and our operating convenience over fuel oil, provides the potential for continuing growth from residential and commercial conversions. In 2007, 14,560 net residential customers (after subtracting disconnected or terminated services) were added, primarily from single- and multi-family new construction, but also due to the conversion of existing residential housing from oil, electric or propane appliances to natural gas. The net increase of all new customers added in 2007 was 15,428. This represents a growth rate of 2.4 percent, which is well above the national average for local gas distribution companies as reported by the American Gas Association.

Industrial Markets

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

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

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

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

We have negotiated special transportation service agreements with some of our largest industrial customers. These special agreements are designed to provide transportation rates that are competitive with the customer’s alternative capital and operating costs of installing direct connections to Northwest Pipeline’s interstate pipeline system, which would allow them to bypass our gas distribution system. These agreements generally prohibit bypass during their terms. Due to the cost pressures that confront a number of our largest customers competing in global markets, bypass continues to be a 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.

Environmental Issues

Properties and Facilities

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

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

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

Future Environmental Issues

We recognize that our business is likely to face future carbon constraints. A variety of legislative and regulatory measures to address greenhouse gas emissions are in various phases of discussion or implementation. These include the proposed international standards (Kyoto Protocol), proposed federal legislation and proposed or enacted state actions to develop statewide or regional programs, each of which have imposed or would impose reductions in greenhouse gas emissions. The outcome of federal and state climate change initiatives cannot be determined at this time, but these initiatives could result in a variety of regulatory programs including potential new regulations, additional charges to fund energy efficiency activities, or other regulatory actions. These actions could result in increased costs associated with operating and maintaining our facilities, could increase other costs to our business and could impact the prices we charge our customers. Because natural gas is a fossil fuel with low carbon content, it is possible that future carbon constraints could create additional demand for natural gas, both for electric production and direct use in homes and businesses.

We continue taking steps to address future environmental issues, including actively participating in policy development through the Oregon Governor's Task Force on Climate Change and leading efforts within the American Gas Association to promote the enactment of fair federal climate change legislation. In 2008, NW Natural's President was appointed to the newly formed Oregon Global Warming Commission. We continue to engage in policy development and in identifying ways to reduce greenhouse gas emissions associated with our operations and our customers' gas use, including the introduction of the Smart Energy program, which allows customers to contribute funds to projects that offset greenhouse gases produced from their natural gas use (see Part II, Item 7., "Regulation and Rates—Rate Mechanisms—Smart Energy Program").

Employees

At December 31, 2007, our workforce consisted of 738 members of the Office and Professional Employees International Union (OPEIU), Local No. 11, AFL-CIO, and approximately 400 management level and other non-bargaining employees. Our labor agreement (Joint Accord) with members of OPEIU that covers wages, benefits and working conditions, extends to May 31, 2009.

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

We have adopted a Code of Ethics for all employees and a Financial Code of Ethics that applies to senior financial employees, both of which are available on our website. Our Corporate Governance

Standards, Director Independence Standards, charters of each of the committees of the Board of Directors and additional information about us are also available on the website.

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

Our Chief Executive Officer certified to the New York Stock Exchange (NYSE) on June 1, 2007 that, as of that date, he was not aware of any violation by the company of NYSE's corporate governance listing standards, and that we had filed with the SEC, as exhibits 31.1 and 31.2 to our Annual Report on Form 10-K for the year ended December 31, 2006, the certificates of the Chief Executive Officer and the Chief Financial Officer certifying the quality of NW Natural's internal control over financial reporting and public disclosures. For the year-ended December 31, 2007, the certificates of the Chief Executive Officer and the Chief Financial Officer are filed with this report as Exhibits 31.1 and 31.2.

ITEM 1A. RISK FACTORS

Our business and financial results are subject to a number of risks and uncertainties, including those set forth below and in other documents we file with the SEC.

Regulatory risk. *The rates we charge customers for gas distribution services are established by the OPUC and the WUTC, and the maximum rates for interstate gas storage services are approved by FERC. The failure of these regulatory authorities to approve rates which provide for recovery of our costs and an adequate return on invested capital may adversely impact our financial condition and results of operations.*

The rates charged to customers must be approved by the applicable regulatory commission. The 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. We expect to continue to make capital expenditures to expand and improve our distribution and storage systems. The failure of any regulatory commission to approve on a timely basis requested rate increases to recover increased costs or to allow an adequate return could adversely impact our financial condition and results of operations. In addition, amounts required to be refunded to customers in accordance with Oregon's automatic regulatory adjustment for income taxes paid could have a material adverse impact on our financial conditions and results of operations.

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

In recent years, natural gas commodity prices have been volatile primarily due to growing demand, especially for power generation, and stagnant North American gas production. In Oregon and in Washington, the utility has PGA tariffs which provide for annual revisions in rates resulting from changes in the cost of purchased gas. 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 that 33 percent of any difference between the actual purchased gas costs and the actual recoveries of gas costs in rates be recognized as current income or expense. Accordingly, higher gas costs than those assumed in setting rates can adversely affect our results of operations.

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

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

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

Our gas purchasing requirements expose us to risks of commodity price movements, while our use of debt and equity financing exposes us to interest rate and other financial market risks. We attempt to manage these exposures and mitigate our risk through enforcement of established risk limits and risk management procedures, including hedging activities, in accordance with our Financial Derivatives Policy. These risk limits and risk management procedures may not always work as planned and cannot entirely eliminate the risks associated with hedging. We also have credit exposure to financial derivative counterparties. Our Financial Derivatives Policy requires counterparties to have a minimum investment-grade credit rating at the time the derivative instrument is entered into, and the policy specifies limits on the contract amount and duration based on each counterparty's credit rating. These practices are subject to regulatory review and, if found to be imprudent, could be disallowed, which could adversely affect our financial condition and results of operations.

Customer growth risk. *Our results of operations may be negatively affected if we are unable to sustain customer growth rates.*

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

Risk of competition. *Our gas distribution business is subject to increased competition with other energy sources.*

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

Higher natural gas prices have eroded, or in some cases eliminated, the competitive price advantage of natural gas over other energy sources. Also, technological improvements in other energy sources could erode our competitive advantage. If natural gas prices continue to rise relative to other energy sources, then our ability to attract new customers could be significantly affected, which could have a negative impact on our customer growth rate and results of operations.

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

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

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

The startup, construction and operation of business development projects involve many risks, including: the inability to obtain required governmental permits and approvals; startup and construction delays; construction cost overruns; competition; inability to negotiate acceptable agreements such as rights-of-way, easements, construction, gas supply or other material contracts; changes in market prices; and operating cost increases. Such unanticipated events could negatively impact our results of operations. These risks apply to our current business development activities, including Palomar Pipeline and the Gill Ranch storage facility in California.

Environmental risk. *Certain of our properties and facilities may pose environmental risks requiring remediation, the cost of which could adversely affect our results of operations and financial condition. Also, management expects that future legislation may impose carbon constraints to address global climate change.*

We own, or previously owned, properties that require environmental remediation or other action. We accrue all material loss contingencies relating to these properties, but our results of operations may be adversely affected to the extent that estimates of the probable costs increase significantly as additional information becomes available and to the extent we are not able to recover the incremental cost from insurance or through customer rates. A regulatory asset has already been recorded for some of these estimated costs. To the extent we are unable to recover these costs in rates or through insurance, we would be required to reduce our regulatory asset which could adversely affect our results of operations and financial condition. In addition, disputes may arise between potentially responsible parties and regulators as to the severity of particular environmental matters and what remediation efforts are appropriate. These disputes could lead to adversarial administrative proceedings or litigation, with uncertain outcomes.

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

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

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

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

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

Higher gas costs and rates may result in increased conservation by customers, which can decrease sales and adversely affect results of operations. The OPUC authorized our conservation tariff, which is designed to recover lost margin due to changes in residential and commercial customers' consumption patterns. The conservation tariff is intended to adjust for increases or decreases in consumption attributable to annual changes in commodity costs or periodic changes in general rates and for deviations between actual and expected usage. The conservation tariff expires in October 2012. The failure of the OPUC to extend the conservation tariff in the future could adversely affect our financial condition and results of operations. We do not have a conservation tariff in Washington.

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, such as leaks, accidents, mechanical problems, fires, storms, landslides and other adverse weather conditions and hazards, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution and disruption of our operations, which in turn could lead to substantial losses. The occurrence of any of these events may not be covered by our insurance policies or recoverable through rates, which could adversely affect our financial condition and results of operations.

Business continuity risk. *We may be adversely impacted by extreme events to which we are not able to promptly respond to and repair our system.*

Extreme events (e.g. terrorism act or national disaster) that target or impact our natural gas distribution, transmission and storage facilities could result in a disruption in our ability to meet customer requirements. These events may also disrupt capital markets and our ability to raise capital, or impact our suppliers or our customers directly. We maintain emergency planning and training programs to remain ready to respond to extreme events. A slow response to extreme events may have an adverse affect on earnings as customers could be without gas for an extended period of time.

Economic risk. *Changes in the economic outlook, including rates of inflation and capital market conditions may have a negative impact on our financial condition and results of operations.*

Our business relies on capital markets to finance our construction costs and other capital expense requirements, and to refund maturing debt, that cannot by funded by operating cash flows. Changes in the economy that impact our ability to access the capital markets at competitive rates may negatively impact our ability to make strategic capital investments. Market disruptions and downgrades of our debt credit ratings may increase our cost of borrowing or negatively impact our ability to access financial markets.

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

Our gas distribution business is subject to a variety of workforce risks, including being able to attract and retain qualified employees, being able to transfer the knowledge and expertise of an aging workforce to new employees as older workers retire and being able to reach collective bargaining agreements with the union that represents about 65 percent of our workers.

ITEM 1B. UNRESOLVED STAFF COMMENTS

Not applicable.

ITEM 2. PROPERTIES

Our natural gas distribution system consists of approximately 13,700 miles of distribution and transmission mains located in our service territory in Oregon and Washington. In addition, the distribution system includes service pipes, meters and regulators, and gas regulating and metering stations. The mains are located in municipal streets or alleys pursuant to valid franchise or occupation ordinances, in county roads or state highways pursuant to valid agreements or permits granted pursuant to statute, or on lands of others pursuant to valid easements obtained from the owners of such lands. We also hold all necessary permits for the crossing of the Willamette River and a number of smaller rivers by our mains.

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

We hold interests in approximately 8,500 net acres of underground natural gas storage and approximately 1,400 net acres of oil and gas leases in Oregon. We own rights to depleted gas reservoirs near Mist, Oregon, that are continuing to be developed and operated as underground gas storage facilities. We also hold an option to purchase future storage rights in certain other areas of the Mist gas field in Oregon, as well as in California related to the Gill Ranch storage project.

In order to reduce risks associated with gas leakage in older parts of our system, we undertook an accelerated pipe replacement program under which we removed or replaced 100 percent of our cast iron mains by October 2000. In 2001, we initiated an accelerated pipe replacement program under which we expect to eliminate all bare steel mains and services in the system by 2021.

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

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

ITEM 3. LEGAL PROCEEDINGS

See Part II, Item 8., Note 12 to Consolidated Financial Statements, "Commitments and Contingencies—Legal Proceedings."

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

There were no matters submitted to a vote of security holders, through the solicitation of proxies or otherwise, during the quarter ended December 31, 2007.

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PART II

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

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

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

	2007		2006	
Quarter Ended	High	Low	High	Low
March 31	$ 46.34	$ 39.79	$ 36.57	$ 32.83
June 30	52.85	44.05	37.04	33.30
September 30	49.37	40.98	40.08	35.81
December 31	50.89	44.28	43.69	38.53

The closing quotations for our common stock on December 31, 2007 and December 29, 2006 were $48.66 and $42.44, respectively.

(B) As of December 31, 2007, there were 7,863 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	2007	2006
February 15	$ 0.355	$ 0.345
May 15	0.355	0.345
August 15	0.355	0.345
November 15	0.375	0.355
Total per share	$ 1.440	$ 1.390

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

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(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, 2007:

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			1,905,528	$ 26,938,905
10/01/07-10/31/07	1,126	$ 46.48	132,300	(6,138,707)
11/01/07-11/30/07	19,984	$ 49.54	61,100	(2,843,169)
12/01/07-12/31/07	1,736	$ 47.90	25,600	(1,224,381)
Total	22,846	$ 49.27	2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2007, 20,873 shares of our common stock were purchased in the open market to meet the requirements of our Dividend Reinvestment and Direct Stock Purchase Plan. In addition, 1,973 shares of our common stock were purchased in the open market during the quarter under equity-based programs. During the three months ended December 31, 2007, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) On May 25, 2000, we announced a program to repurchase up to 2 million shares, or up to $35 million in value, of NW Natural’s common stock through a repurchase program that has been extended annually. The purchases are made in the open market or through privately negotiated transactions. In April 2006, the Board increased the authorization from 2 million shares to 2.6 million shares and increased the dollar limit from $35 million to $85 million. In April 2007, the Board extended the program through May 31, 2008 and increased the authorization from 2.6 million shares to 2.8 million shares and increased the dollar limit from $85 million to $100 million. During the three months ended December 31, 2007, 219,000 shares of our common stock were purchased pursuant to this program. Since the program’s inception through December 31, 2007, we have repurchased 2,124,528 shares of common stock at a total cost of $83.3 million.

On September 28, 2007, we entered into a Stock Purchase Plan Engagement Agreement with our broker that established a trading plan for our repurchase program that qualified for the safe harbors provided by Rule 10b-18 and Rule 10b5-1 under the Exchange Act. That agreement expired on November 9, 2007.

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ITEM 6. SELECTED FINANCIAL DATA

Thousands, except per share amounts and ratio of earnings to fixed charges	For the year ended December 31, 2007	2006	2005	2004	2003
Utility operating revenues:					
Residential sales	$ 555,312	$ 536,468	$ 471,502	$ 383,067	$ 328,346
Commercial sales	298,800	290,666	250,287	200,424	176,336
Industrial - firm sales	54,567	66,986	64,507	45,259	33,578
Industrial - interruptible sales	74,876	93,107	100,740	55,380	23,655
Unbilled revenues[1]	-	-	-	-	14,474
Total gas sales revenues	983,555	987,227	887,036	684,130	576,389
Transportation	14,191	12,800	10,755	12,655	17,968
Regulatory adjustment for income taxes paid[2]	5,996	-	-	-	-
Other	12,228	161	2,862	4,160	7,627
Total gross utility operating revenues	1,015,970	1,000,188	900,653	700,945	601,984
Cost of gas sold	639,094	648,081	563,772	399,176	323,128
Revenue taxes	25,001	24,840	21,633	16,865	14,650
Utility operating revenues	351,875	327,267	315,248	284,904	264,206
Non-utility operating revenues	17,167	12,909	9,745	6,591	9,210
Net operating revenues	$ 369,042	$ 340,176	$ 324,993	$ 291,495	$ 273,416
Net income	$ 74,497	$ 63,415	$ 58,149	$ 50,572	$ 45,983
Redeemable preferred stock dividend requirements	-	-	-	-	294
Earnings applicable to common stock	$ 74,497	$ 63,415	$ 58,149	$ 50,572	$ 45,689
Average common shares outstanding:					
Basic	26,821	27,540	27,564	27,016	25,741
Diluted	26,995	27,657	27,621	27,283	26,061
Earnings per share of common stock:					
Basic	$ 2.78	$ 2.30	$ 2.11	$ 1.87	$ 1.77
Diluted	$ 2.76	$ 2.29	$ 2.11	$ 1.86	$ 1.76
Dividends paid per share of common stock	$ 1.44	$ 1.39	$ 1.32	$ 1.30	$ 1.27
Total assets - at end of period	$ 2,014,183	$ 1,956,856	$ 2,042,304	$ 1,732,195	$ 1,585,379
Long-term debt	$ 512,000	$ 517,000	$ 521,500	$ 484,027	$ 500,319
Ratio of earnings to fixed charges	3.92	3.40	3.32	3.02	2.84

(1) Unbilled revenues have been allocated by customer class for the years 2004 through 2007.

(2) Regulatory adjustment for income taxes paid is the result of the implementation of the utility regulation as described in Part II, Item 7., "Results of Operations - Regulatory Matters - Regulatory Adjustment for Income Taxes Paid," and "Comparison of Gas Distribution Operations - Regulatory Adjustment for Income Taxes Paid."

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

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SELECTED FINANCIAL DATA (continued)

Thousands, except customer and gas cost per therm data	For the year ended December 31, 2007	2006	2005	2004	2003
Capitalization - at end of period					
Common stock equity	$ 594,751	$ 599,545	$ 586,931	$ 568,517	$ 506,316
Long-term debt	512,000	517,000	521,500	484,027	500,319
Total capitalization	$1,106,751	$1,116,545	$1,108,431	$1,052,544	$1,006,635
Gas sales and transportation deliveries (therms):					
Residential	398,960	382,665	371,538	352,356	343,534
Commercial	249,659	242,683	233,987	222,875	226,257
Industrial - firm	52,340	66,971	74,880	62,843	55,314
Industrial - interruptible	89,128	112,736	149,106	104,278	47,994
Unbilled therms[1]	-	-	-	-	12,099
Total gas sales	790,087	805,055	829,511	742,352	685,198
Transportation	424,882	387,594	328,056	389,514	414,554
Total volumes delivered	1,214,969	1,192,649	1,157,567	1,131,866	1,099,752
Customers (average for period):					
Residential	580,346	564,700	545,163	525,976	510,336
Commercial	60,749	59,889	58,914	57,973	56,504
Industrial - firm	634	650	666	629	362
Industrial - interruptible	189	197	201	178	98
Transportation	128	99	78	106	179
Total customers	642,046	625,535	605,022	584,862	567,479
Customer statistics:					
Heat requirements:					
Actual degree days	4,374	4,089	4,178	3,853	3,952
Percent colder (warmer) than average	3%	(4%)	(2%)	(10%)	(7%)
Average annual use per customer in therms:					
Residential	687	678	682	670	673
Commercial	4,110	4,052	3,972	3,844	4,004
Gas purchased cost per therm - net (cents)	75.00	75.37	71.42	56.60	46.99

(1) Unbilled therms have been allocated by customer class for the years 2004 through 2007.

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 three years ended December 31, 2007. References in this discussion to "Notes" are to the Notes to consolidated financial statements in this report.

The consolidated financial statements include the accounts of NW Natural, which principally consist of our regulated local gas distribution business, our regulated gas storage business, and other regulated and non-regulated investments primarily in energy-related businesses, including our wholly-owned subsidiaries, NNG Financial Corporation (Financial Corporation) and Gill Ranch Storage, LLC (Gill Ranch). In this report, the term "utility" is used to describe our regulated gas distribution business, and the term "non-utility" is used to describe our gas storage business (gas storage) and our other non-regulated investments and business activities (other segment), including investments in a recently announced intrastate pipeline project in Oregon (Palomar Pipeline) (see "Strategic Opportunities," below, and Note 2).

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

Executive Summary

Highlights of 2007:

- Net income increased 17 percent to $74.5 million, and diluted earnings per share increased 21 percent to $2.76 per share;
- Net operating revenues from our utility increased 8 percent to $351.9 million;
- Net operating revenues from our gas storage business increased 33 percent to $17.0 million;
- Cash flow from operations increased 24 percent to $183.6 million, reflecting strong earnings and deferred gas cost savings;
- Ranked best in the West and second-best nationally in overall residential customer satisfaction among gas utilities according to a J.D. Power and Associates survey;
- Conservation tariff and weather normalization mechanisms were extended in Oregon through October 2012;
- Smart Energy Program, a carbon-offset billing option for customers, was implemented as the first program of its kind for a standalone gas company to address greenhouse gas emissions;
- Announced plans to develop investments in a natural gas transmission pipeline in Oregon and an underground gas storage facility in central California (see "Strategic Opportunities," below);
- Mist storage capacity was expanded by 1.8 Bcf to approximately 16 Bcf; and,
- Quarterly common stock dividend rate increased 6 percent to $0.375 per share in the fourth quarter of 2007, making this the 52nd consecutive year of increasing dividends paid to shareholders.

Our primary businesses consist of our regulated utility and gas storage. Factors critical to the success of the utility business include: maintaining a safe and reliable distribution system; acquiring an adequate supply of gas; providing distribution services at a competitive price; and being able to recover the operating and capital costs of the utility in the rates charged to customers. The utility is regulated by two state commissions, the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC). Factors critical to the success of our gas storage business segment include the ability to: develop additional storage capacity at competitive market prices; plan for the replacement of capacity that is expected to be recalled by the utility to serve its core customers in the future; and obtain timely and reasonable rate changes. Our gas storage businesses charge rates approved by the Federal Energy Regulatory Commission (FERC). The Gill Ranch project is expected to be subject to regulation by the California Public Utilities Commission (CPUC), if completed.

2008 Outlook

In 2008, management expects to focus on the following four areas:

Core Business Improvement. We plan to incorporate new technology into our operations while honing new processes established in the recent changes to our operating model. Our goal is to integrate and to streamline operations and provide our employees with tools to become even more effective and efficient.

Strategic Position. In our rapidly changing business environment, we will strive to continue achieving shareholder value while balancing the interests of our customers and communities. In doing so, we will continue to develop plans in response to potential climate change legislation as well as to address regulatory, business development and workforce challenges and opportunities.

Business Development. We intend to advance our key natural gas infrastructure investments, such as the Palomar Pipeline and Gill Ranch storage projects, while exploring new growth opportunities. See "Strategic Opportunities," below.

Organizational Effectiveness. As employees are our most highly valued resource, we intend to continue to support our employees with well defined practices, training and technology to achieve our goals.

Issues, Challenges and Performance Measures

Managing the business in a period of gas price volatility. Our gas acquisition strategy is designed to secure sufficient supplies of natural gas to meet the needs of our utility’s core customers. Equally important, however, is our strategy to hedge gas prices for a significant portion of our annual purchase requirements based upon the market outlook and our core utility’s gas load forecast. We believe we have sufficient supplies of natural gas under contract to meet the needs of our core customers, but price increases could change our earnings outlook and our competitive advantage. If gas prices increase, it could affect our ability to add residential and commercial customers and could result in industrial customers shifting their businesses’ energy needs to alternative fuel sources. We continue to develop new gas acquisition strategies to manage gas prices and to efficiently meet market demands.

Customer growth. Our growth is largely driven by new residential construction, and while we expect to continue with a customer growth rate above the national average for local gas distribution companies due to the growing market in the Pacific Northwest, we have experienced a slowdown in new construction which is expected to continue through 2008. For the 12 months ended December 31, 2007, our annual growth rate was 2.4 percent, compared to 3.1 percent for the comparable period ended December 31, 2006. A prolonged slowdown in residential new construction could adversely impact our future results of operations.

Strategic Opportunities

Business Process Redesign. To address these economic and competitive challenges we will continue to evaluate our business processes and costs in our new operating model and to improve those processes where long-term efficiencies could be gained. We targeted a number of areas where we could restructure to gain efficiencies, including more centralization and more standardized processes. To date, we are on schedule to meet the target workforce reductions of 150 to 200 employees by late 2009. We are also currently completing the implementation of the first phase of a new integrated information system, with the second phase of the new system installation expected to commence early in 2008. These technology investments are expected to help facilitate additional business initiatives, as well as help to improve overall operational efficiencies throughout NW Natural.

Pipeline Diversity. In September 2006, we announced that we were evaluating a possible equity investment in a natural gas transmission pipeline that would connect TransCanada Gas Transmission Northwest's (GTN) interstate transmission line to our local gas distribution system (Palomar Pipeline). The proposed pipeline is intended to diversify our gas delivery options, including the enhancement of reliability for our customers by providing an alternate transportation path for, and an alternative gas supply source to, gas purchases in Alberta and, including the possible delivery of supplies from a liquefied natural gas (LNG) facility that is proposed on the Columbia River. In August 2007, we entered into an agreement with GTN for the purpose of developing, designing, permitting, constructing and owning the pipeline. During the planning and permitting phase we expect to contribute our 50 percent of the estimated $30 million for permitting and planning, which is anticipated to occur during the 2007-2009 period. We believe there is sufficient interest from potential pipeline users to warrant proceeding with the permitting phase of the project. We, along with GTN, will determine at a later date whether to proceed with development of the project beyond the permitting phase. If constructed, we estimate the total cost for the entire 220 mile pipeline to be between $600 million and $700 million. NorthernStar LLC, developer of a proposed Bradwood Landing LNG terminal on the Columbia River, may elect to take capacity on the Palomar Pipeline should the Bradwood Landing terminal and the Palomar Pipeline be constructed.

Gas Storage Development. In September 2007, we announced a joint project with Pacific Gas & Electric Company (PG&E) to develop an underground natural gas storage facility near Fresno, California. We formed Gill Ranch, a wholly owned subsidiary of NW Natural, to develop and operate the facility. Gill Ranch will initially own 75 percent of this storage project and PG&E will own 25 percent. The new storage facility is expected to provide approximately 20 Bcf of underground gas storage capacity, and will include 25 miles of transmission pipeline, when the initial phase is completed. We estimate our share of the total cost for the initial phase of development to be between $150 million and $160 million over the next three years, which represents 75 percent of the estimated total project cost. We conducted an open season to gauge interest in the storage facility from October 2007 to December 2007, and the results indicated a strong level of interest in gas storage at Gill Ranch from potential storage customers. We expect to file an application with the CPUC for a Certificate of Public Convenience and Necessity in mid-2008 and, if granted, Gill Ranch will be subject to CPUC regulation with respect, among other things, to rates, the issuance of securities, lien grants and sales of property. We expect the initial phase of Gill Ranch to be in-service by late 2010.

Earnings and Dividends

Net income was $74.5 million, or $2.76 a diluted share, for the year ended December 31, 2007, compared to $63.4 million, or $2.29 a diluted share, and $58.1 million, or $2.11 a share, for the years ended December 31, 2006 and 2005, respectively. Returns on equity for these three years were 12.5 percent, 10.7 percent and 10.1 percent, respectively.

2007 compared to 2006:

Positive factors contributing to increased earnings were:

- increased utility volumes and sales to residential and commercial customers primarily from customer growth contributed $9.7 million to margin (see "Results of Operations—Comparison of Gas Distribution Operations," below);
- increased margin of $6.0 million from a regulatory adjustment for income taxes paid;
- increased margin from regulatory sharing of gas cost savings, up from $8.1 million in 2006 to $12.1 million in 2007, and from reversing temporary adjustments related to derivative contracts that settled in 2007, reflecting gains of $2.9 million in 2007 compared to losses of $2.9 million in 2006; and
- increased margin of $4.2 million from gas storage operations, primarily due to an expansion of firm storage capacity and higher revenue sharing from asset optimization.

Partially offsetting the above positive factors were:

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

2006 compared to 2005:

Positive factors contributing to increased earnings were:

- increased utility volumes and net operating revenues (margin) from sales to residential and commercial customers due to 3.1 percent customer growth, plus extended coverage from the weather normalization and conservation mechanisms in Oregon, partially offset by weather that was 4 percent warmer than average and 2 percent warmer than 2005 (see "Results of Operations—Comparison of Gas Distribution Operations," below);
- increased margin from regulatory sharing of gas cost savings, from $4.2 million in 2005 to $8.1 million in 2006, partially offset by a $2.9 million temporary unrealized loss related to a derivative contract that settled and reversed in 2007; and
- increased gas storage margin over the prior year, primarily due to increased storage contract volumes and increased optimization revenue from the independent energy marketing company.

Partially offsetting the above positive factors were:

- increased property tax and depreciation expenses related to increased utility plant in service, which were partially covered by revenue increases approved in the 2006 Purchased Gas Adjustment (PGA) filings in Oregon and Washington;

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

Dividends paid on our common stock were $1.44 a share in 2007, compared to $1.39 a share in 2006 and $1.32 a share in 2005. The current indicated annual dividend rate is $1.50 per share.

Application of Critical Accounting Policies and Estimates

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

Our most critical estimates or judgments involve regulatory cost recovery, revenue recognition, derivative instruments, pension assumptions, income taxes and environmental contingencies. Management has discussed the estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board. Our critical accounting policies and estimates are described below.

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

Regulatory Accounting

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

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

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

We continue to apply SFAS No. 71 in accounting for our regulated utility operations. Future regulatory changes or changes in the competitive environment could require us to discontinue the application of SFAS No. 71 for some or all of our regulated businesses. This would require the write-off of those regulatory assets and liabilities that would no longer be probable of recovery from or refund to customers. Based on current regulatory and competitive conditions, we believe that it is reasonable to expect continued application of SFAS No. 71 for our regulated activities, and that all of our regulatory assets and liabilities at December 31, 2007 and 2006 are recoverable or refundable through future customer rates. See Note 1, "Industry Regulation."

Revenue Recognition

Utility revenues, derived primarily from the sale and transportation of natural gas, are recognized when gas is delivered to and received by the customer. Revenues are accrued for gas delivered to customers, but not yet billed, based on estimates of gas deliveries from the last meter reading date to month end (accrued unbilled revenues). Accrued unbilled revenues are primarily based on a percentage estimate of our unbilled gas each month, which is dependent upon a number of factors, some of which require management's judgment. These factors include total gas receipts and deliveries, customer meter reading dates, customer usage patterns and weather. Accrued unbilled revenue estimates are reversed the following month when actual billings occur. Estimated unbilled revenues at December 31, 2007 and 2006 were $78.0 million and $87.5 million, respectively. The decrease in accrued unbilled revenues at year-end 2007 was primarily due to lower gas prices included in customer rates. If the estimated percentage of unbilled volume at December 31, 2007 was adjusted up or down by 1 percent, then our unbilled revenues, net operating revenues and net income would have increased or decreased by an estimated $3.0 million, $1.5 million and $0.9 million, respectively.

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

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

Accounting for Derivative Instruments and Hedging Activities

Our Financial Derivatives Policy and Gas Acquisition Policy set forth guidelines for using financial derivative instruments to support prudent risk management strategies within designated parameters. These policies specifically prohibit the use of derivatives for trading or speculative purposes. The accounting rules for determining whether a contract meets the definition of a derivative instrument or qualifies for hedge accounting treatment are complex. The contracts that qualify as derivative instruments are recorded on our balance sheet at fair value. If certain regulatory conditions are met, then the fair value is recorded together with an offsetting entry to a regulatory asset or liability account pursuant to SFAS No. 71 (see Note 1, "Industry Regulation") and no gain or loss is recognized in current income. The gain or loss from the fair value of a derivative instrument that is subject to regulatory deferral is included in the recovery from, or refund to, utility customers in future periods (see "Regulatory Accounting," above). If a derivative contract is not subject to regulatory deferral, then the accounting treatment for gains and losses is made in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149, collectively referred to as SFAS No. 133 (see Note 1, "Derivatives" and "Industry Regulation"). Our estimate of fair value is determined from period-to-period based on an internal discounted cash flow model for swap contracts and on a Black-Scholes model for option contracts. The estimate of fair value may change significantly from period-to-period depending on market conditions and prices. These changes may have an impact on our results of operations, but the impact would largely be mitigated due to the majority of our derivatives activities being subject to regulatory deferral treatment. For estimated fair values at December 31, 2007 and 2006, see Note 11.

Commodity-based derivative contracts entered into by the utility after our annual PGA filing for the current gas contract period are subject to a regulatory incentive sharing mechanism in Oregon, with 67 percent of unrealized gains and losses recorded to a regulatory asset or liability account. The remaining 33 percent is recognized in current income for contracts not qualifying for hedge accounting or is recognized in Other Comprehensive Income for contracts qualifying for hedge accounting. An interest rate swap qualifies for hedge accounting under SFAS No. 133. During the fourth quarter of 2006, we entered into a number of financial derivatives related to commodity purchases by the utility after our PGA filing. The $2.9 million loss was reversed during 2007 in the cost of gas when the derivative contract settled.

Derivative contracts are subjected to a hedge effectiveness test to determine the financial statement treatment of each specific derivative. As of December 31, 2007, all of our derivatives were effective economic hedges and either qualified or were expected to qualify for regulatory deferral, or hedge accounting treatment. We utilize the hypothetical derivative method under SFAS No. 133 to determine the hedge effectiveness of our interest rate swap and the dollar offset method under SFAS No. 133 for all other derivative contracts. The effectiveness test applied to financial derivatives is dependent on the type of derivative and its use.

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

Thousands	2007	2006	2005
Net gain (loss) on commodity-price swaps—utility	$(41,954)	$(18,849)	$90,205
Net loss on commodity-price options—utility	(662)	(1,160)	(1,315)
Subtotal on commodity—utility	(42,616)	(20,009)	88,890
Net gain on foreign currency forward purchases—utility	662	355	532
Total realized net gain (loss)	$(41,954)	$(19,654)	$89,422

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. Unrealized gains and losses resulting from mark-to-market valuations are generally not recognized in current income or other comprehensive income, but are recorded as regulatory liabilities or regulatory assets, which are offset by a corresponding balance in non-trading derivative assets or liabilities (see Note 11).

Accounting for Pensions

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

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

Effective December 31, 2006, the funded status of our pension plans was required to be recognized in accordance with SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Benefit Plans" (SFAS No. 158). SFAS No. 158 requires balance sheet recognition of the overfunded or underfunded status of pension plans in accumulated other comprehensive income (AOCI), net of tax, based on the fair value of plan assets compared to the actuarial value of future benefit obligations. However, the pension costs relating to certain NW Natural pension plans are recovered in utility rates based on SFAS No. 87, and as such we received regulatory approval from the OPUC pursuant to SFAS No. 71, to record a regulatory asset or regulatory liability, rather than include AOCI in common equity, for the funded status of those plans (see "Regulatory Accounting", above, and Note 1, "Industry Regulation").

A number of factors are considered in developing pension assumptions, including an evaluation of relevant discount rates, expected long-term investment returns, plan asset allocations, expected changes in salaries, wages and retirement benefits, analyses of current market conditions and input from actuaries and other consultants. For the December 31, 2007 measurement date, we:

- updated the pension discount rate assumptions from a range of 6.00 percent to 6.05 percent to a range of 6.75 percent to 6.87 percent. The new rate assumptions were determined for each plan based on a matching of the estimated cash flow, which reflects the timing and amount of future benefit payments, to the Citigroup Above Median Curve, which consists of high quality bonds rated AA- or higher by Standard & Poor's or Aa3 or higher by Moody's Investors Service;

- confirmed the expected rate of future compensation increases between 4.00 and 5.00 percent;
- confirmed the expected long-term return on plan assets at 8.25 percent; and
- reviewed and updated other key assumptions as needed.

Changes in valuation assumptions impact our projected benefit obligations. The projected benefit obligations at December 31, 2007 decreased $23.9 million due to an increase in the discount rate assumptions and increased by $3.4 million due to an increase in the benefit payments for certain retirees.

We determine the expected long-term rate of return on plan assets by averaging the expected earnings for the target asset portfolio. In developing our expected rate of return assumption, we evaluate an analysis of historical actual performance and long-term return projections, which gives consideration to the current asset mix and our target asset allocation. The actual annualized returns on plan assets, net of management fees, for the past one-year, five-year and 10-year periods ended December 31, 2007 were 8.98 percent, 14.17 percent and 8.92 percent, respectively.

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

Thousands, except percent	Change in Assumption	Impact on 2007 Pension Costs	Impact on Benefit Obligations at Dec. 31, 2007
Discount rate	(0.25%)	$ 569	$ 8,682
Expected long-term return on plan assets	(0.25%)	$ 560	N/A

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

Accounting for Income Taxes

We account for income taxes in accordance with SFAS 109 and Financial Accounting Standards Board (FASB) Interpretation No. 48 (FIN 48), which require that deferred tax assets and liabilities be recognized using enacted tax rates for the effect of temporary differences between the book and tax basis of recorded assets and liabilities. SFAS 109 and FIN 48 also require that deferred tax assets be reduced by a valuation if it is more likely than not that some portion or all of the deferred tax asset will not be realized. We adopted the provisions of FIN 48 on January 1, 2007. At the date of adoption and as of December 31, 2007, we did not have a liability for unrecognized tax benefits as all positions taken are considered highly certain. Our net long-term deferred tax liability totaled $203.1 million at December 31, 2007. This liability is estimated based on the expected future tax consequences of items recognized in the financial statements. After application of the federal statutory tax rate to book income, judgment is required with respect to the timing and deductibility of expense in our tax returns. For state income tax and other taxes, judgment is also required with respect to the apportionment among the various jurisdictions. A valuation allowance is recorded if we expect that it is more likely than not that our deferred tax assets will not be realized. At December 31, 2007, we did not have a valuation allowance due to our expectation that all of these assets will be realized.

SFAS No. 109 also requires the recognition of additional deferred income tax assets and liabilities for temporary differences where regulators require us to flow through deferred income tax benefits or expenses in the ratemaking process of the regulated utility (regulatory tax assets and liabilities). This is consistent with the ratemaking policies of the OPUC and WUTC. Regulatory tax assets and liabilities are recorded to the extent we believe they will be recoverable from, or refunded to, customers in future rates. At December 31, 2007 and 2006, we had regulatory assets representing differences between book and tax basis related to pre-1981 property of $68.6 million and $67.1 million, respectively, and recorded an offsetting deferred tax liability for the same amounts (see Note 1, "Income Tax Expense"). We believe that it is reasonable to expect recovery of these regulatory assets through future customer rates. However, future regulatory changes could require the write-off of all or a portion of these regulatory assets should they no longer be probable of recovery in future rates (see "Regulatory Accounting," above, and Notes 1 and 8).

Contingencies

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

With respect to environmental liabilities and related costs we develop estimates based on a review of information available from recently completed studies and negotiations involving several sites. Using sampling data, feasibility studies, existing technology and enacted laws and regulations, we estimated that the total future expenditures for environmental investigation, monitoring and remediation are $38.3 million as of December 31, 2007. It is our policy to accrue the full amount of such liability when information is sufficient to reasonably estimate the amount of probable liability. When information is not available to reasonably estimate the probable liability, or when only the range of probable liabilities can be estimated and no amount within the range is more likely than another, then it is our policy to accrue at the lower end of the range. Accordingly, due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot be reasonably estimated. Therefore, we have recorded the liabilities at an amount that reflects the most likely estimate or the low end of the range.

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

Results of Operations

Regulatory Matters

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates, systems of accounts and issuance of securities by the OPUC and the WUTC. In 2007, 93 percent of our utility gas deliveries and 91 percent of our utility operating revenues were derived from Oregon customers and the balance from Washington customers. Future earnings and cash flows from utility operations will be determined largely by the pace of continued customer growth in the residential and commercial markets and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery for our utility gas costs, operating and maintenance costs and investments made in utility plant.

General Rate Cases

Our most recent general rate increase in Oregon authorized rates to customers based on a return on shareholders' equity (ROE) of 10.2 percent and was effective September 1, 2003. We retain all of our earnings up to a threshold level equal to our authorized ROE of 10.2 percent plus 300 basis points, subject to adjustment up or down each year based on movements in long-term interest rates. Our most recent general rate case in Washington authorized a revenue increase of $3.5 million per year but did not specifically authorize an ROE and was effective July 1, 2004. Our plans are to file a general rate case in Washington in 2008.

The current maximum cost-based rates for our interstate gas storage services were approved by FERC in 2005. These rates are designed to reflect updated costs related to development of the Mist gas storage facility from 2001 through 2005. Pursuant to this approval, we were required to file either a petition for rate approval or a cost and revenue study with FERC by January 18, 2008. We requested and received an extension to enable us to file a cost and revenue study based on our actual 2007 results. We expect to file the study by March 31, 2008.

Oregon Rate Case Moratorium. 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, or expansion of our automated meter reading program if an existing joint meter reading program with a local electric utility ends. This agreement does not impact our ability to file annual rate adjustments to reflect changes in gas purchase costs under our PGA mechanism and to collect, or refund, prior year's gas cost deferrals.

Rate Mechanisms

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

In October 2007, the OPUC and the WUTC approved rate decreases effective on November 1, 2007 under our PGA mechanism. The rate reduction lowered average monthly bills of Oregon residential customers by 8.0 percent and those of Washington residential customers by 9.8 percent. The PGA mechanism reflects the January 2007 rates approved by FERC for interstate pipeline suppliers. Pursuant to the PGA tariffs, approved rate changes effective November 1, 2006 increased average monthly bills of Oregon residential sales customers by 3.5 percent and those of Washington residential sales customers by 2.6 percent. In 2005, the OPUC approved a PGA rate increase averaging 15.2 percent for Oregon residential sales customers, and the WUTC approved a rate increase averaging 12.0 percent for Washington residential sales customers, both effective October 1, 2005.

The OPUC is currently conducting a formal review of the PGA process used by natural gas utilities in Oregon covering gas portfolio requirements, incentive sharing levels and filing requirements, among other items. The review is expected to be completed in 2008. Implementation of any changes to the PGA mechanism is likely to become effective with the 2008 PGA filing.

Conservation Tariff. In October 2002, the OPUC authorized the implementation of a "conservation tariff," which is a rate mechanism designed to adjust margin to compensate the utility for changes in consumption patterns due to residential and commercial customers’ conservation efforts. The tariff is a decoupling mechanism that is intended to break the link between earnings and the quantity of energy consumed by customers, removing any 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 utility revenues.

The Oregon conservation tariff includes two components: (1) a price elasticity adjustment, which adjusts rates annually for expected increases or decreases in customer volumes due to annual changes in commodity costs or periodic changes in our general rates; and (2) a conservation adjustment calculated on a monthly basis to account for the difference between actual and expected volumes (also referred to as the decoupling adjustment). The margin adjustment resulting from differences between actual and expected volumes under the decoupling component is recorded to a deferral account, which

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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 for current customer growth. See Part II, Item 7., "Results of Operations—Comparison of Gas Distribution Operations," below.

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

Weather Normalization. In Oregon, the OPUC has 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, decreasing rates when the weather is colder than average and increasing rates when it is warmer than average. The mechanism is applied to our residential and commercial customers' bills between December 1 and May 15 for each heating season. The mechanism adjusts the margin component of customers' rates to reflect average weather, which uses the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers (see "Comparison of Gas Distribution Operations," below). We do not have a weather normalization mechanism approved for our Washington customers, which accounts for about 10 percent of our utility revenues.

Excess Earnings Test. We are subject to an excess earnings test requirement in which we retain all of our earnings up to a threshold level equal to our authorized ROE of 10.2 percent plus 300 basis points. Revenues equivalent to 33 percent of any earnings above the threshold are required to be refunded to customers. The excess earnings threshold is subject to adjustment up or down each year based on movements in long-term interest rates. In 2007 and 2006, the threshold after adjustment was 13.40 percent and 13.44 percent, respectively. No amounts were required to be refunded to customers as a result of the 2006 or 2005 earnings test, and we do not expect that any amounts will be required to be refunded to customers as a result of the 2007 earnings test, which will be reviewed by the OPUC during the second quarter of 2008. The OPUC's annual formal review process to test for excess earnings ensures that we are allowed to pass through 100 percent of prudently incurred gas costs into rates. In Washington, we are not subject to an annual excess earnings test, and 100 percent of all prudently incurred gas costs are passed through into customer rates in the annual PGA.

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

Pipeline Integrity Cost Recovery. In July 2004, the OPUC approved the accounting treatment and full recovery for the cost of our 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 (see "Financial Condition—Cash Flows—Investing Activities," below). We classify our costs as either capital expenditures or regulatory assets, accumulate the costs over each 12 months ending September 30, and recover the costs, subject to audit, through rate changes effective with the annual PGA. The accounting and rate treatment for these costs extends through September 30, 2008 and may be reviewed for potential extension after that date. We do not have any special accounting or rate treatment for pipeline integrity costs incurred in the state of Washington.

Smart Energy Program. Effective September 1, 2007, the OPUC approved our "Smart Energy" program. Smart Energy allows residential and commercial customers to offset greenhouse gases produced from their natural gas use. The Smart Energy rate is designed to neutralize the impact of greenhouse gases, such as carbon dioxide and methane, by funding projects that prevent, reduce or capture emissions released into the atmosphere. Offset funds collected from customers participating in the program will be forwarded to The Climate Trust and these funds will specifically target the reduction of methane emissions from farm operations.

Regulatory Adjustment for Income Taxes Paid

During 2005, the Oregon legislature passed legislation, effective January 1, 2006, intended to ensure that utilities do not collect in rates more income taxes than they actually pay to taxing authorities. The OPUC adopted permanent rules to implement this legislation in September 2006, which were subsequently amended, with the revised rules approved in September 2007. The OPUC rules require us to identify the amount of income taxes paid, as well as the amount of taxes authorized to be collected in rates during the tax year. If amounts paid and amounts collected differ by more than $100,000, the OPUC is required to direct the utility to implement a rate schedule with an automatic adjustment clause to refund or surcharge for the difference. For more information regarding this requirement, see "Comparison of Gas Distribution Operations—Regulatory Adjustment for Income Taxes Paid," below.

In January 2008, the Internal Revenue Service (IRS) ruled on our request for a Private Letter Ruling on the issue of whether this state law complies with the provisions of federal tax law, including the normalization requirements of the Internal Revenue Code. The IRS ruling indicated that, as presented to them, the Oregon law does not violate the normalization requirements of federal tax law.

Comparison of Gas Distribution Operations

The following table summarizes the composition of gas utility volumes and revenues for the years ended December 31, 2007, 2006 and 2005:

Thousands except degree day and customer data	2007	2006	2005	Favorable/ (Unfavorable) 2007 vs. 2006	2006 vs. 2005
Utility volumes - therms:					
Residential sales	398,960	382,665	371,538	16,295	11,127
Commercial sales	249,659	242,683	233,987	6,976	8,696
Industrial - firm sales	52,340	66,971	74,880	(14,631)	(7,909)
Industrial - firm transportation	161,790	150,153	135,807	11,637	14,346
Industrial - interruptible sales	89,128	112,736	149,106	(23,608)	(36,370)
Industrial - interruptible transportation	263,092	237,441	192,249	25,651	45,192
Total utility volumes sold and delivered	1,214,969	1,192,649	1,157,567	22,320	35,082
Utility operating revenues - dollars:					
Residential sales	$ 555,312	$ 536,468	$ 471,502	$ 18,844	$ 64,966
Commercial sales	298,800	290,666	250,287	8,134	40,379
Industrial - firm sales	54,567	66,986	64,507	(12,419)	2,479
Industrial - firm transportation	5,927	4,901	4,087	1,026	814
Industrial - interruptible sales	74,876	93,107	100,740	(18,231)	(7,633)
Industrial - interruptible transportation	8,264	7,899	6,668	365	1,231
Regulatory adjustment for income taxes paid [1]	5,996	—	—	5,996	—
Other revenues	12,228	161	2,862	12,067	(2,701)
Total utility operating revenues	1,015,970	1,000,188	900,653	15,782	99,535
Cost of gas sold	639,094	648,081	563,772	8,987	(84,309)
Revenue taxes	25,001	24,840	21,633	(161)	(3,207)
Utility net operating revenues (utility margin)	$ 351,875	$ 327,267	$ 315,248	$ 24,608	$ 12,019
Utility margin: [2]					
Residential sales	$ 213,698	$ 204,951	$ 195,098	$ 8,747	$ 9,853
Commercial sales	85,960	83,334	78,919	2,626	4,415
Industrial - sales and transportation	31,333	32,383	31,632	(1,050)	751
Miscellaneous revenues	4,966	4,333	4,990	633	(657)
Other margin adjustments	11,906	2,610	2,950	9,296	(340)
Margin before regulatory adjustments	347,863	327,611	313,589	20,252	14,022
Weather normalization mechanism	(2,496)	2,282	(1,308)	(4,778)	3,590
Decoupling mechanism	512	(2,626)	2,967	3,138	(5,593)
Regulatory adjustment for income taxes paid [1]	5,996	—	—	5,996	—
Utility margin	$ 351,875	$ 327,267	$ 315,248	$ 24,608	$ 12,019
Customers - end of period:					
Residential customers	589,676	575,116	556,667	14,560	18,449
Commercial customers	61,397	60,523	59,543	874	980
Industrial customers	939	945	953	(6)	(8)
Total number of customers - end of period	652,012	636,584	617,163	15,428	19,421
Actual degree days	4,374	4,089	4,178		
Percent colder (warmer) than average [3]	3%	(4%)	(2%)		

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

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

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

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 contributes to changes in margin based on changes in residential and commercial customer consumption, and we have a weather normalization mechanism that adjusts customer bills up or down contributing to changes in margin based on above- or below-average temperatures during the winter heating season (see "Results of Operations—Regulatory Developments—Rate Mechanisms," above). Both mechanisms are designed to reduce the volatility of our utility earnings.

2007 compared to 2006:

Total utility margin increased $24.6 million or 8 percent in 2007 compared to 2006 with residential and commercial customers contributing an additional $11.4 million to margin in 2007, not including the effects of the weather normalization and decoupling mechanisms. The $1.0 million decrease in margin from industrial customers in 2007 was partially offset by a decrease in revenue adjustments from regulatory deferrals and amortizations and miscellaneous fees. The weather normalization and decoupling mechanisms decreased margin by a net $1.6 million in 2007 compared to 2006, primarily reflecting colder weather, partially offset by an increase in decoupling that reflects higher than expected consumption. Total utility volumes sold and delivered in 2007 were about the same as last year. An increase in regulatory sharing of gas cost savings of $4.0 million and a regulatory adjustment related to income taxes paid of $6.0 million also contributed to the increase in margin (see "Regulatory Adjustment for Income Taxes Paid," and "Cost of Gas Sold," below).

Volume increases in 2007 were due mainly to residential and commercial customer growth, which reflects a net increase of 15,428 customers during 2007, or an annual growth rate of 2.4 percent. Our growth rate has slowed but remains well above the national average for local gas distribution companies. Recent economic conditions have slowed the level of new construction in our service territory.

Our weather normalization mechanism reduced margin by $2.5 million for the year ended December 31, 2007 based on weather that was 3 percent colder than average, compared to an increase of $2.3 million in added margin for the year ended December 31, 2006 based on weather that was 4 percent warmer than average. The weather normalization mechanism is designed to balance our margins when weather deviates from average.

The decoupling mechanism increased margin by $0.5 million in 2007, after adjusting for price elasticity in the annual Oregon PGA filing, compared to a margin decrease of $2.6 million in 2006. Decoupling is designed to adjust to our margin to reflect changes in customer usage due to customer conservation efforts.

2006 compared to 2005:

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

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

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

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

Residential and Commercial Sales

Residential and commercial sales markets are impacted by seasonal weather patterns, energy prices, competition from other energy sources and economic conditions in our service areas. Typically, 80 percent or more of our annual utility operating revenues are derived from gas sales to weather-sensitive residential and commercial customers. Although variations in temperatures between periods will affect volumes of gas sold to these customers, the effect on margin and net income is significantly reduced due to our weather normalization mechanism in Oregon where about 90 percent of our customers are served. Beginning in 2006, this mechanism became effective for the period from December 1 through May 15 of each heating season. Approximately 10 percent of our eligible Oregon customers have opted out of the mechanism. In Oregon, we also have a conservation decoupling mechanism that is intended to break the link between our earnings and the quantity of gas consumed by our customers, so that we do not have an incentive to discourage customers from conserving energy. In Washington, where the remaining 10 percent of our customers are served, we do not have a weather normalization or a conservation decoupling mechanism. As a result, these mechanisms do not fully insulate the utility from earnings volatility due to weather and conservation. See the above tables under "Comparison of Gas Distribution Operations" for the adjustments to utility margin revenues from the weather normalization and decoupling mechanisms.

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

2007 compared to 2006:

- operating revenues increased 3 percent, primarily due to a 4 percent increase in volumes;
- volumes were 4 percent higher, primarily reflecting 2.4 percent customer growth and 7 percent colder weather; and

- margin before regulatory adjustments for weather normalization, decoupling and income taxes paid was 4 percent higher, reflecting increased volumes from customer growth and higher gas cost savings from our PGA incentive sharing mechanism in Oregon (see "Cost of Gas Sold," below).

2006 compared to 2005:

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

Industrial Sales and Transportation

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

2007 compared to 2006:

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

2006 compared to 2005:

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

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

Regulatory Adjustment for Income Taxes Paid

Based upon the revised rules issued by the OPUC in September 2007, we filed our 2007 Tax Report for the 2006 tax year on October 15, 2007. For the 2006 tax year, we estimated the utility was entitled to recover $1.7 million through a surcharge to our Oregon utility customers based on taxes paid that were greater than taxes collected, which was primarily driven by gains from gas cost savings from the PGA incentive sharing mechanism in 2006. The increase in Oregon revenues for this surcharge is expected to go into effect June 1, 2008 and would be recovered in a one-time adjustment to customers. For the 2007 tax year, we estimate the utility will again be entitled to a surcharge for taxes paid in excess of taxes collected in rates, largely driven by gains from gas cost savings from the PGA incentive sharing mechanism in 2007. For 2007, we recognized an estimated surcharge of $4.3 million. The combined 2006 and 2007 surcharge estimate of $6.0 million was recognized in 2007 and is included in "Gross operating revenues." Deferred income tax expense of $2.4 million was also recognized in 2007 related to the 2006 and 2007 estimated surcharges, resulting in a net contribution to earnings of $3.6 million (see "Regulatory Matters—Regulatory Adjustment for Income Taxes Paid," above).

Other Revenues

Other revenues include miscellaneous fee income as well as revenue adjustments reflecting deferrals to, or amortizations from, regulatory asset or liability accounts other than deferrals relating to gas costs. Other revenues increased net operating revenues by $12.2 million in 2007, compared to $0.2 million in 2006 and $2.9 million in 2005.

2007 compared to 2006:

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

2006 compared to 2005:

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

Cost of Gas Sold

Natural gas commodity prices had risen significantly in recent years, but the cost of gas decreased slightly in 2007. The effects of higher commodity prices and price volatility on core utility customers are mitigated, in part, through our use of underground storage facilities, fixed-price commodity hedge contracts and short term sales of excess gas supply and transportation capacity to off-system customers in periods when core utility customers do not require the full amount of contract gas supplies or firm pipeline capacity.

The total cost of gas sold was $639.1 million in 2007, a decrease of $9.0 million or 1 percent compared to 2006, and cost of gas sold in 2006 was $648.1 million, an increase of $84.3 million or 15 percent higher than 2005. The cost per therm of gas sold includes current gas purchases, gas drawn from storage inventory, gains or losses from commodity hedges, margin from off-system gas sales, pipeline demand charges, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use.

Under the PGA tariff in Oregon, our net income is affected within defined limits by changes in purchased gas costs (see "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above). In each of the last three years, our actual gas costs were lower than the gas costs embedded in rates, with the effect being that our share of the cost savings increased margin by $12.1 million, $8.1 million and $4.2 million for 2007, 2006 and 2005, respectively.

We use natural gas derivatives, primarily fixed-price commodity swaps, under the terms of our Financial Derivatives Policy, to help manage our exposure to floating price gas purchase contracts (see "Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities," above, and Note 11). We realized net losses of $42.0 million and $20.0 million from our financial hedges in 2007 and 2006, respectively, compared to a gain of $88.9 million in 2005. Gains and losses from the financial hedging of utility gas purchases generally are included in cost of gas, but generally do not impact net income because the hedges are factored into our PGA deferrals and annual rate changes. To the extent that any utility gas hedge is entered into after the annual PGA filing, then the gains and losses are subject to our PGA incentive sharing mechanism with 67 percent deferred and 33 percent recorded to current income.

Business Segments Other than Local Gas Distribution

Gas Storage

We earned $8.7 million in net income from our non-utility gas storage business segment in 2007, after regulatory sharing and income taxes, equivalent to 32 cents a share, compared to $6.0 million or 21 cents a share in 2006 and $4.6 million or 17 cents a share in 2005 (see Note 2). Earnings from this business segment were higher in 2007 primarily because of increased revenues from additional contract storage and higher margins from our contract with an independent energy marketing company that optimizes the value of our utility assets.

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

Other

The other business segment primarily consists of a wholly-owned subsidiary, Financial Corporation, as well as various other non-utility investments, including an investment in an aircraft that is leased to a U.S. airline, our equity investment in a proposed natural gas transmission pipeline project (Palomar Pipeline), and our wholly-owned subsidiary, Gill Ranch (see Note 9). Our net investment balance in Financial Corporation at December 31, 2007 and 2006 was $1.4 million and $2.6 million, respectively. The decrease primarily reflects the sale in October 2007 of investments in alternative energy projects for $2.1 million plus our portion of the investments' retained cash, resulting in an after-tax gain of $0.9 million. Our net investment balance in the aircraft lease at December 31, 2007 and 2006 was $3.2 million and $5.3 million, respectively, with the decrease primarily due to the receipt in March 2007 of the final payment due under the terms of the original 20 year lease agreement. Our equity investment balance in the proposed natural gas pipeline project with GTN was $6.0 million at December 31, 2007 and a negligible amount at December 31, 2006 (see "Strategic Opportunities—Pipeline Diversity," above).

Net income from our other business segment was $0.8 million for each of 2007, 2006 and 2005. In 2007, we recognized net income of $1.2 million from Financial Corporation, primarily related to the sale of limited partnership interests in two wind power electric generation projects in California. These sales generated an after-tax gain of $0.9 million. This was offset in part by the net loss we recognized related to the Gill Ranch investment of $0.3 million.

Subsidiaries

Financial Corporation

Operating results in 2007 were net income of $1.2 million, compared to $0.2 million in 2006 and $0.3 million in 2005. The increase is primarily due to the gain from the sale of Financial Corporation's limited partnership interests in two wind power electric generation projects in California in October 2007.

Gill Ranch

In September 2007, we announced a joint project with PG&E to develop a new underground natural gas storage facility at Gill Ranch near Fresno, California. We formed Gill Ranch as a subsidiary of NW Natural. See "Strategic Opportunities—Gas Storage Development," above.

Operating Expenses

Operations and Maintenance

Operations and maintenance expenses increased by $5.9 million in 2007, or 5 percent, compared to 2006 which in part reflects certain strategic initiatives which increased operations and maintenance expense. These initiatives included additional training expenses ($1.2 million), promotional and safety campaigns ($1.2 million) and maintenance projects ($1.9 million). Absent these strategic initiatives, operations and maintenance would have increased 1 percent. Operations and maintenance expense increased $1.3 million in 2006, or 1 percent, compared to 2005. The following summarizes the major factors that contributed to changes in operations and maintenance expense:

2007 compared to 2006:

- a $3.8 million increase in employee compensation and benefit expense, primarily due to bonuses related to improved financial and operating results on annual and long-term incentive plan performance goals;
- a $1.9 million increase in costs for maintenance projects and geo-hazard repairs;

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- a $0.9 million increase in training, maintenance and telecommunication expenses related to the implementation of the first phase of a new integrated information system; and
- a $0.3 million increase in start up expenses for the Smart Energy program.

Partially offsetting the above increases was:

- a $1.5 million decrease in severance expenses.

2006 compared to 2005:

- a $2.0 million increase in payroll expense, primarily due to bonuses related to improved results on annual and long-term incentive plan performance goals;
- a $1.1 million increase in severance expenses related to the 2006 severance incentive plan; and
- a $0.8 million increase in stock option expense due to the required adoption of SFAS No. 123R related to stock-based compensation expense.

Partially offsetting the above increases were:

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

General Taxes

General taxes, which are principally comprised of property and payroll taxes, increased $0.9 million, or 4 percent, in 2007 compared to 2006, and increased $1.2 million, or 5 percent, in 2006 compared to 2005. The major factors that contributed to changes in general taxes are:

2007 compared to 2006:

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

2006 compared to 2005:

- a $0.7 million increase in property taxes;
- a $0.5 million increase in regulatory fees based on higher revenue; and
- a $0.1 million decrease in payroll taxes.

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Depreciation and Amortization

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

Thousands	2007	2006	2005
Plant and property:			
Utility plant:			
Depreciable	$2,013,191	$1,925,837	$1,839,206
Non-depreciable, including construction work in progress	38,970	37,661	36,238
	2,052,161	1,963,498	1,875,444
Non-utility property:			
Depreciable	56,444	36,952	36,920
Non-depreciable, including construction work in progress	10,705	5,700	3,916
	67,149	42,652	40,836
Total plant and property	$2,119,310	$2,006,150	$1,916,280
Depreciation and amortization:			
Utility plant	$ 67,410	$ 63,552	$ 60,935
Non-utility property	933	883	710
Total depreciation and amortization expense	$ 68,343	$ 64,435	$ 61,645
Average depreciation rate - utility	3.4%	3.4%	3.4%
Average depreciation rate - non-utility	2.1%	2.5%	2.6%

Total depreciation and amortization expense increased by $3.9 million, or 6 percent, in 2007 and by $2.8 million, or 5 percent, in 2006. The increased expense for both years is primarily due to additional investments in utility plant to meet continuing customer growth and to make system improvements (see "Financial Condition—Cash Flows—Investing Activities," below, and Note 9). In 2006, we completed a depreciation study on all company plant and property, which generally indicates that depreciation rates overall would be reduced if we maintain the existing average service life depreciation method. We applied for the adoption of new depreciation rates using the average service life method. However, if the OPUC or WUTC were to require us to adopt a different depreciation method such as the equal life group method, then depreciation rates could increase. Utility depreciation rates and methods are subject to review and approval by the OPUC and WUTC, and new rates will not be placed into service until depreciation rate proceedings are approved. We submitted the updated depreciation study for regulatory approval in 2007 and will implement the new rates upon approval. We do not anticipate that adoption of these new rates will have a material impact on our financial condition or results of operations.

Other Income and Expense—Net

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

Thousands	2007	2006	2005
Gains from company-owned life insurance	$ 1,939	$2,609	$ 1,856
Interest income	537	363	403
Other non-operating expenses	(2,789)	(852)	(1,393)
Net interest on deferred regulatory accounts	84	(177)	282
Gain on sale of equity investments	1,544	-	-
Earnings from equity investments of Financial Corporation	130	191	57
Total other income	$ 1,445	$2,134	$ 1,205

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

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

Interest Charges—Net of Amounts Capitalized

Interest charges—net of amounts capitalized in 2007 was $1.4 million, or 4 percent, lower than in 2006, reflecting lower balances on long-term debt outstanding due to the redemption of $20 million in March 2007 and $9.5 million in May 2007. In 2006, interest charges—net of amounts capitalized was $2.0 million, or 5 percent, higher than in 2005, reflecting higher interest rates on short-term debt balances and slightly higher average balances of long-term debt outstanding during the period due to the issuance of $50 million in June 2005 and $25 million in December 2006. The increase in an allowance for funds used during construction (AFUDC) in 2006 reflects higher construction work in progress balances. The average interest crediting rate for AFUDC, comprised of short-term and long-term borrowing rates, as appropriate, was 5.4 percent in 2007, 4.7 percent in 2006 and 3.1 percent in 2005.

Income Tax Expense

The increase in income tax expense of $7.8 million or 22% in 2007, compared to 2006 was primarily due to higher consolidated earnings and a slightly higher effective tax rate of 37.2% in 2007 compared to 36.4% in 2006. The increase in our effective tax rate was primarily a result of a lower non-taxable gain on company-owned life insurance. We expect our effective tax rate in 2008 to remain consistent with our 2007 rate. Income tax expense increased by $3.5 million in 2006, as compared to total income tax expense of $32.7 million in 2005, and the effective tax rate increased 0.4 percent from an effective tax rate of 36.0 percent in 2005. For more information on our income taxes, including a reconciliation between the statutory federal income tax rate and the effective rate, see Note 1.

Financial Condition

Capital Structure

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

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

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

Liquidity and Capital Resources

At December 31, 2007, we had $6.1 million in cash and cash equivalents compared to $5.8 million at December 31, 2006. Short-term liquidity is provided by cash from operations and from the sale of commercial paper notes, which are supported by committed lines of credit. We have available a committed bank facility totaling $250 million through May 31, 2012 (see "Credit Agreement," below, and Note 6). Short-term debt balances typically are reduced toward the end of the winter heating season as a significant amount of our current assets, primarily accounts receivable and gas inventories, are converted into cash.

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

To provide long-term financing, we periodically issue and sell secured or unsecured debt, preferred stock or common stock. In June 2005 and December 2006, we issued $50 million and $25 million of secured medium-term notes, respectively. At December 31, 2007, we had $85 million available for future issuance of debt or equity securities under a universal shelf registration, which was approved by the OPUC (see "Financing Activities," below). On January 8, 2008, we filed a new universal shelf registration for an unspecified amount of securities to replace the existing universal shelf registration. Under new rules, NW Natural may designate the amount of securities to be registered at the time of issuance.

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

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

Dividend Policy

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

Off-Balance Sheet Arrangements

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

Contractual Obligations

The following table shows our contractual obligations at December 31, 2007 by maturity and type of obligation.

	Payments Due in Years Ending December 31,						
Thousands	2008	2009	2010	2011	2012	Thereafter	Total
Commercial paper	$ 143,100	$ -	$ -	$ -	$ -	$ -	$ 143,100
Long-term debt maturities	5,000	-	35,000	10,000	40,000	427,000	517,000
Interest on long-term debt	33,632	33,417	33,406	30,858	28,536	313,056	472,905
Postretirement benefit payments[1]	16,603	17,345	18,510	19,063	19,857	110,959	202,337
Capital leases	532	393	255	26	-	-	1,206
Operating leases	4,257	4,184	4,177	4,140	4,265	32,003	53,026
Gas purchase contracts[2]	302,709	118,936	53,253	24,106	24,106	44,193	567,303
Gas pipeline commitments	82,348	63,526	61,090	64,989	49,977	131,501	453,431
Other purchase commitments	27,683	1,421	14	-	-	-	29,118
Total	$ 615,864	$ 239,222	$ 205,705	$ 153,182	$ 166,741	$ 1,058,712	$ 2,439,426

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

(2) All gas purchase contracts use price formulas tied to monthly index prices. Commitment amounts are based on index prices at December 31, 2007.

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

Holders of certain long-term debt have put options that, if exercised, would require repurchases of up to $20 million principal amount in each of 2008 and 2009. If repurchased prior to maturity, then the interest obligation shown in the above table would be reduced in future years. The interest rate on the long-term debt issues with put options ranges between 6.65 percent and 7.05 percent.

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

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

Commercial Paper

Our primary source of short-term funds is from the sale of commercial paper notes. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas inventories and accounts receivable, short-term debt may be used to temporarily fund capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by committed lines of credit (see "Credit Agreement," below). We had $143.1 million in commercial paper notes outstanding at December 31, 2007, compared to $100.1 million at December 31, 2006.

Credit Agreement

In May 2007, we entered into a credit agreement for unsecured revolving loans totaling $250 million with a syndication of lenders, replacing the prior $200 million bilateral credit agreements which were terminated. The new credit agreement is available and committed for a term of five years expiring on May 31, 2012, which may be extended for additional one-year periods thereafter subject to lender approval. The credit agreement allows us to request increases in the total commitment amount, up to a maximum amount of $400 million. The credit agreement also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. The credit agreement continues to be used primarily as back-up credit support for the notes payable issued under our commercial paper program. Commercial paper borrowing provides the liquidity to meet our working capital and interim financing requirements. Under the terms of the credit agreement, we pay upfront fees, annual commitment fees and administrative agent fees, but we are not required to maintain compensating bank balances. The interest rates on outstanding loans, if any, under the credit agreement are based on our long-term unsecured debt ratings and on then-current market interest rates. All principal and unpaid interest under the credit agreement is due and payable on May 31, 2012, subject to extensions if any. There were no outstanding balances on this credit agreement at December 31, 2007 or on prior credit agreements at December 31, 2006.

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

The credit agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2007. Our previous credit agreements required us to maintain an indebtedness to total capitalization ratio of 65 percent or less, which we were in compliance with at December 31, 2006.

Credit Ratings

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

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

In July 2007, Moody's revised our ratings outlook from "Stable" to "Positive." Both of the rating agencies have assigned us an investment grade rating. These credit ratings and ratings outlook are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell or hold our securities. Each rating should be evaluated independently of any other rating.

Redemptions of Long-Term Debt

We redeemed long-term debt during 2007, 2006 and 2005 as follows:

Thousands	Redeemed in 2007	Redeemed in 2006	Redeemed in 2005
Medium-Term Notes			
6.34% Series B due 2005	$ -	$ -	$ 5,000
6.38% Series B due 2005	-	-	5,000
6.45% Series B due 2005	-	-	5,000
6.05% Series B due 2006	-	8,000	-
6.31% Series B due 2007	20,000	-	-
6.80% Series B due 2007	9,500	-	-
Convertible Debentures			
7.25% Series due 2012	-	-	528

Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, changes in working capital requirements and other cash and non-cash adjustments to operating results. In 2007, cash flow from net income and operating activity adjustments, excluding working capital changes, increased by $23.0 million. Working capital changes in 2007 increased cash flow by $12.1 million.

In 2006, our cash flow from net income and operating activity adjustments, excluding working capital changes, increased by $44.6 million, primarily due to a $31.0 million decrease in cash contributions to our qualified defined benefit pension plans and a $18.2 million increase in cash collections from deferred gas costs and improved operating results, partially offset by a decrease in deferred income tax benefits reflecting the expiration of higher tax benefits realized in 2004 from accelerated bonus depreciation. Working capital changes in 2006 increased cash flow by $24.9 million.

The overall change in cash flow from operating activities in 2007 compared to 2006 was an increase of $35.1 million. The overall change in cash flow from operations in 2006 was an increase of $69.5 million compared to 2005. The significant factors contributing to the cash flow changes between years are as follows:

2007 compared to 2006:

- an increase in net income added $11.1 million to cash flow;
- an increase in cash of $11.2 million related to a smaller reduction in 2007 in deferred income taxes compared to 2006;
- the increase in regulatory liabilities in 2007 related to deferred gas costs increased cash flow by $17.9 million, reflecting deferral activity between the two years with respect to purchased gas cost savings and off-system gas sales under our PGA tariff;
- a decrease in cash flow of $17.5 million due to change in deferred regulatory and other costs;
- an increase of $25.8 million due to a decrease in 2007 in accounts receivable and accrued unbilled revenue at year end compared to an increase in 2006;
- a decrease of $13.4 million in 2007 compared to 2006 resulting from income tax refunds received during 2006;
- an increase in accounts payable in 2007 compared to a decrease in 2006, increased cash $27.5 million;
- a decrease of $9.8 million in 2007 due to an increase in gas inventory in 2007 compared to a decrease in 2006; and
- a decrease of $16.6 million from a decrease in accrued taxes due to higher cash payments in 2007.

2006 compared to 2005:

- an increase in net income added $5.3 million to cash flow;
- a decrease in cash of $26.0 million related to a deferred income tax benefit in 2006 compared to a deferred income tax expense in 2005;

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

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

Investing Activities

Cash requirements for investing activities in 2007 totaled $117.5 million, up from $90.6 million in 2006. Cash requirements for the acquisition and construction of utility plant were $93.8 million in 2007, down slightly from $95.3 million in 2006. Cash requirements for investments in non-utility property increased to $29.9 million in 2007, compared to $1.8 million in 2006, primarily related to investments in Mist gas storage, Gill Ranch and Palomar Pipeline.

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

Investments in our pipeline integrity management program were $11.5 million in 2007, compared to $11.0 million in 2006 and $6.1 million in 2005. These costs are estimated at approximately $50 million to $100 million over a 10-year period through 2012. The costs are accumulated over each 12 months ending September 30, and the capitalized costs, subject to audit, are recovered through the annual PGA based on adjustments to rate base each year. The approved regulatory accounting and rate treatment for these costs extends through September 30, 2008, and may be reviewed for potential extension after that date.

During the five-year period 2008 through 2012, utility construction expenditures are estimated at between $500 and $600 million. The estimated level of capital expenditures over the next five years reflects continued customer growth, gas storage development at Mist, technology improvements and utility system improvements, including requirements under the Pipeline Safety Improvement Act of 2002. Most of the required funds are expected to be internally generated over the five-year period and any remaining funding will be obtained through the issuance of long-term debt or equity securities, with short-term debt providing liquidity and bridge financing.

Our utility and non-utility capital expenditures for 2008 are estimated to total between $90 million and $100 million. This estimate does not include costs of the potential Palomar Pipeline or Gill Ranch projects, or other investments that may be driven by our business process redesign (see "Strategic Opportunities," above). In December 2003, the U.S. Department of Transportation’s Office of Pipeline Safety (now the Pipeline Hazardous Materials Safety Administration) issued a rule that specifies the detailed requirements for transmission pipeline integrity management plans as mandated by the Pipeline Safety Act. See Part I., Item 1., "Pipeline Safety." We continued to achieve our milestones, completing the required inspection of the top 50 percent highest risk transmission pipelines in 2007. We are currently on track to meet the next milestone to complete the inspection of all transmission pipelines in HCAs by December 2012.

Financing Activities

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

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

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

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

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

In 2000, we announced a program to repurchase up to 2 million shares, or up to $35 million in value, of our common stock through a repurchase program. In 2006 that program was modified to 2.6 million shares and $85 million in value, and the program was further increased in 2007 to 2.8 million shares and $100 million and extended through May 2008. The purchases are made in the open market or through privately negotiated transactions. Repurchases pursuant to the program in 2007 totaled 963,428 shares or $44.2 million; in 2006 totaled 395,500 shares or $16.0 million; and in 2005 totaled 410,200 shares, or $14.9 million. Since the program’s inception, we have repurchased an aggregate 2,124,528 shares of common stock at a total cost of $83.3 million (see Part II, Item 5, "Market for the Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities," above).

In 2007, we produced free cash flow of $27.5 million, compared to free cash flow of $19.7 million in 2006. In 2005 we had negative free cash flow of $49.3 million. Free cash flow is the amount of cash remaining after the payment of all cash expenses, capital expenditures (investment activities) and dividends. Free cash flow is a non-GAAP financial measure, but we believe this supplemental information enables the reader of the financial statements to better understand our cash generating ability and to benefit from seeing cash flow results from management's perspective in addition to the traditional GAAP presentation. We monitor free cash flow as one measure of our return on investments. Provided below is a reconciliation from cash provided by operations (GAAP basis) to our non-GAAP free cash flow.

Thousands (year ended December 31)	2007	2006	2005
Cash provided by operating activities	$ 183,640	$148,566	$ 79,066
Cash used in investing activities	(117,479)	(90,567)	(92,008)
Cash dividend payments on common stock	(38,613)	(38,298)	(36,376)
Free cash flow	$ 27,548	$ 19,701	$(49,318)

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

Pension Cost and Funding Status of Qualified Retirement Plans

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Generally, it is our policy to contribute at least the minimum amount required by Internal Revenue Code regulations and the Employee Retirement Income Security Act of 1974. It is also our intent to contribute additional amounts sufficient on a sound actuarial basis to maintain funding targets and provide for the payment of future benefits under the plans. Our qualified defined pension plans are currently funded at nearly 100 percent of the projected benefit obligation at December 31, 2007. For more information see Note 7.

Ratios of Earnings to Fixed Charges

For the years ended December 31, 2007, 2006 and 2005, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 3.92, 3.40 and 3.32, respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with SFAS No. 5, "Accounting for Contingencies," (see "Application of Critical Accounting Policies and Estimates—Contingencies," above). At December 31, 2007, a cumulative $63.1 million in environmental costs was recorded as a regulatory asset, consisting of $24.8 million of costs paid to-date, $35.1 million for additional environmental accruals for costs expected to be paid in the future and accrued regulatory interest of $3.2 million. If it is determined that both the insurance recovery and future customer rate recovery of such costs is not probable, then the costs will be charged to expense in the period such determination is made. For further discussion of contingent liabilities, see Note 12.

New Accounting Pronouncements

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Supply Risk

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

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

Commodity Price Risk

Natural gas commodity prices are subject to fluctuations due to unpredictable factors including weather, pipeline transportation congestion and other factors that affect short-term supply and demand. Commodity-price swap, put and call option contracts (financial hedge contracts) are used to convert certain natural gas supply contracts from floating prices to fixed prices. These financial hedge contracts are generally included in our annual PGA filing, subject to a prudency review. At December 31, 2007 and 2006, notional amounts under these commodity swap, put and call option contracts totaled $287.6 million and $349.7 million, respectively. If the related financial derivative contracts had been settled on December 31, 2007, a regulatory loss of $ 12.8 million would have been realized and deferred (see Note 11). The $12.8 million unrealized loss is an estimate of future cash flows that are expected to be paid as follows: $10.5 million in 2008 and $2.3 million by October 31, 2009. The amount realized will change based on market prices at the time contracts settle. We monitor the liquidity of our financial derivative contracts and, based on the existing open interest in the contracts held, we believe existing contracts to be liquid. All of our commodity financial hedge contracts settle by October 31, 2009.

Interest Rate Risk

We are exposed to interest rate risk associated with new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. Interest rate risk is primarily managed through the issuance of fixed-rate debt with varying maturities. We may also enter into financial derivative instruments, including interest rate swaps, options and other hedge products, to manage and mitigate interest rate exposure. During the fourth quarter of 2007, we entered into a forward starting interest rate swap with a notional amount of $50 million to hedge the interest rate on our next long-term debt issuance, which is expected to occur in the latter part of 2008.

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This swap is with an AA/Aaa rated counterparty and qualifies as a cash flow hedge under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149 (collectively referred to as SFAS No. 133).

Holders of certain long-term debt have put options that, if exercised, would accelerate maturities by $20 million in each of 2008 and 2009 (see Note 5 and Note 11).

Foreign Currency Risk

The costs of certain natural gas commodity supplies and certain pipeline services purchased from Canadian suppliers are subject to changes in the value of the Canadian currency in relation to the U.S. currency. Foreign currency forward contracts are used to hedge against fluctuations in exchange rates with respect to the purchases of natural gas from Canadian suppliers. At December 31, 2007 and 2006, notional amounts under foreign currency forward contracts totaled $6.1 million and $5.0 million, respectively. As of December 31, 2007, no foreign currency forward contracts extended beyond December 31, 2008. If all of the foreign currency forward contracts had been settled on December 31, 2007, a gain of $0.1 million would have been realized (see Note 11).

Credit Risk

Credit exposure to suppliers. Certain suppliers that sell us gas have either relatively low credit ratings or are not rated by major credit rating agencies. To manage this supply risk, we purchase gas from a number of different suppliers. We evaluate and continuously monitor suppliers' creditworthiness and maintain the ability to require additional financial assurances, including deposits, letters of credit or surety bonds, in case a supplier defaults. In the event of a supplier's failure to deliver contracted volumes of gas, the regulated utility would need to replace those volumes at prevailing market prices, which may be higher or lower than the original transaction prices. We believe these costs would be subject to the PGA sharing mechanism discussed above. Since most of our commodity supply contracts are priced at the monthly market index price, and we have significant storage flexibility, we believe that it is unlikely that a supplier default would have a material adverse effect on our financial condition or results of operations.

Credit exposure to financial derivative counterparties. Periodically we may have credit exposure to financial derivative counterparties based on the estimated fair value of derivative contracts outstanding. At December 31, 2007, in aggregate our financial derivative counterparties owed us $0.1 million while we owed our counterparties a net $14.1 million. Our Financial Derivatives Policy requires counterparties to have a specified minimum credit rating at the time the derivative instrument is entered into, and the policy sets forth limits on the contract amount and duration based on each counterparty's credit rating.

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

	Financial Derivative Position by Credit Rating Unrealized Fair Value Gain (Loss)	
Thousands	Dec. 31, 2007	Dec. 31, 2006
AAA/Aaa	$ (309)	$ -
AA/Aa	(13,941)	(40,955)
A/A	123	-
BBB/Baa	-	-
Total	$ (14,127)	$ (40,955)

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

Additionally we have master contracts in place with each of our derivative counterparties that include provisions for posting or calling for collateral. Generally we can obtain cash or marketable securities as collateral with one day's notice. We utilize various collateral management strategies to reduce liquidity risk. The collateral provisions vary by counterparty but are not expected to result in any significant posting of collateral, if any. We have performed stress tests on the portfolio and concluded that the liquidity risk from collateral calls is not material. During 2007, we neither called for nor posted collateral with any of our derivative counterparties. Our derivative credit exposure is primarily with investment grade banks rated AA-/Aa3 or higher. Contracts are diversified across counterparties to reduce credit and liquidity risk.

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

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

Weather Risk

We are exposed to weather risk primarily from our regulated utility business. A large percentage of our utility margin is volume driven, and current rates are based on an assumption of average weather. In 2003, the OPUC approved a weather normalization mechanism for residential and commercial customers. This mechanism affects customer bills between December 1 through May 15 of each winter heating season, increasing or decreasing the margin component of customers' rates to reflect "average" weather using the 25-year average temperature for each day of the billing period. The mechanism is intended to stabilize the recovery of our utility's fixed costs and reduce fluctuations in customers' bills due to colder or warmer than average weather. Customers in Oregon are allowed to opt out of the weather normalization mechanism. As of December 31, 2007, about 9 percent of our Oregon customers had opted out. In addition to the Oregon customers opting out, our Washington residential and commercial customers account for approximately 10 percent of our total customer base and are not covered by weather normalization. The combination of Oregon and Washington customers not covered by a weather normalization mechanism is less than 20 percent of all residential and commercial customers.

Forward-Looking Statements

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

- prevailing state and federal governmental policies and regulatory actions with respect to allowed rates of return, industry and rate structure, purchased gas cost and investment recovery, acquisitions and dispositions of assets and facilities, operation and construction of plant facilities, present or prospective wholesale and retail competition, changes in tax laws and policies and changes in and compliance with environmental and safety laws, regulations, policies and orders, and laws, regulations and orders with respect to the maintenance of pipeline integrity;
- application of the OPUC rules interpreting Oregon legislation intended to ensure that utilities do not collect more income taxes in rates than they actually pay to government entities;
- weather conditions, pandemic events and other natural phenomena, including earthquakes or other geohazard events;
- unanticipated population growth or decline and changes in market demand caused by changes in demographic or customer consumption patterns;
- competition for retail and wholesale customers;
- market conditions and pricing of natural gas relative to other energy sources;
- the creditworthiness of customers, suppliers and financial derivative counterparties;
- our dependence on a single pipeline transportation provider for natural gas supply;
- property damage associated with a pipeline safety incident, as well as risks resulting from uninsured damage to our property, intentional or otherwise;
- financial and operational risks relating to business development and investment activities, including the proposed natural gas pipeline project with GTN and the proposed Gill Ranch storage facility;
- unanticipated changes that may affect our liquidity or access to capital markets;

- our ability to maintain effective internal controls over financial reporting in compliance with Section 404 of the Sarbanes-Oxley Act of 2002;
- unanticipated changes in interest or foreign currency exchange rates or in rates of inflation;
- economic factors that could cause a severe downturn in certain key industries, thus affecting demand for natural gas;
- unanticipated changes in operating expenses and capital expenditures;
- changes in estimates of potential liabilities relating to environmental contingencies;
- unanticipated changes in future liabilities relating to employee benefit plans, including changes in key assumptions;
- capital market conditions, including their effect on financing costs, the fair value of pension assets and on pension and other postretirement benefit costs;
- potential inability to obtain permits, rights of way, easements, leases or other interests or other necessary authority to construct pipelines, develop storage or complete other system expansions; and
- legal and administrative proceedings and settlements.

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

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Supplemental Schedules Omitted

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

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

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

Management assessed the effectiveness of NW Natural's internal control over financial reporting as of December 31, 2007. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework*.

Based on our assessment and those criteria, management has concluded that NW Natural maintained effective internal control over financial reporting as of December 31, 2007.

The effectiveness of internal control over financial reporting as of December 31, 2007 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in this annual report.

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

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

February 29, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying table of contents present fairly, in all material respects, the financial position of Northwest Natural Gas Company and its subsidiaries at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying table of contents presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and the financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

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

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

/s/ PricewaterhouseCoopers LLP
Portland, Oregon
February 29, 2008

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF INCOME

Thousands, except per share amounts (year ended December 31)	2007	2006	2005
Operating revenues:			
Gross operating revenues	$ 1,033,193	$ 1,013,172	$ 910,486
Less: Cost of sales	639,150	648,156	563,860
Revenue taxes	25,001	24,840	21,633
Net operating revenues	369,042	340,176	324,993
Operating expenses:			
Operations and maintenance	120,488	114,560	113,216
General taxes	25,288	24,419	23,185
Depreciation and amortization	68,343	64,435	61,645
Total operating expenses	214,119	203,414	198,046
Income from operations	154,923	136,762	126,947
Other income and expense - net	1,445	2,134	1,205
Interest charges - net of amounts capitalized	37,811	39,247	37,283
Income before income taxes	118,557	99,649	90,869
Income tax expense	44,060	36,234	32,720
Net income	$ 74,497	$ 63,415	$ 58,149
Average common shares outstanding:			
Basic	26,821	27,540	27,564
Diluted	26,995	27,657	27,621
Earnings per share of common stock:			
Basic	$ 2.78	$ 2.30	$ 2.11
Diluted	$ 2.76	$ 2.29	$ 2.11

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2007	2006
Assets:		
Plant and property:		
Utility plant	$ 2,052,161	$ 1,963,498
Less accumulated depreciation	615,533	574,093
Utility plant - net	1,436,628	1,389,405
Non-utility property	67,149	42,652
Less accumulated depreciation and amortization	7,904	6,916
Non-utility property - net	59,245	35,736
Total plant and property	1,495,873	1,425,141
Current assets:		
Cash and cash equivalents	6,107	5,767
Accounts receivable	69,442	82,070
Accrued unbilled revenue	78,004	87,548
Allowance for uncollectible accounts	(2,890)	(3,033)
Regulatory assets	17,598	31,509
Fair value of non-trading derivatives	2,903	5,109
Inventories:		
Gas	71,079	68,576
Materials and supplies	8,865	9,552
Income taxes receivable	122	-
Prepayments and other current assets	25,569	21,695
Total current assets	276,799	308,793
Investments, deferred charges and other assets:		
Regulatory assets	175,938	164,771
Fair value of non-trading derivatives	324	1,448
Other investments	54,070	47,985
Other	11,179	8,718
Total investments, deferred charges and other assets	241,511	222,922
Total assets	$ 2,014,183	$ 1,956,856

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2007	2006
Capitalization and liabilities:		
Capitalization:		
Common stock	$ 331,595	$ 371,127
Earnings invested in the business	266,658	230,774
Accumulated other comprehensive income (loss)	(3,502)	(2,356)
Total common stock equity	594,751	599,545
Long-term debt	512,000	517,000
Total capitalization	1,106,751	1,116,545
Current liabilities:		
Notes payable	143,100	100,100
Long-term debt due within one year	5,000	29,500
Accounts payable	119,731	113,579
Taxes accrued	13,259	21,230
Interest accrued	2,827	2,924
Regulatory liabilities	61,326	11,919
Fair value of non-trading derivatives	14,829	38,772
Other current and accrued liabilities	29,794	21,455
Total current liabilities	389,866	339,479
Deferred credits and other liabilities:		
Deferred income taxes and investment tax credits	206,340	210,084
Regulatory liabilities	213,764	202,982
Pension and other postretirement benefit liabilities	41,619	52,690
Fair value of non-trading derivatives	3,758	11,031
Other	52,085	24,045
Total deferred credits and other liabilities	517,566	500,832
Commitments and contingencies (see Note 12)	-	-
Total capitalization and liabilities	$ 2,014,183	$ 1,956,856

See Notes to Consolidated Financial Statements.

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

Thousands	Common Stock and Premium	Earnings Invested in the Business	Unearned Stock Compensation	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Comprehensive Income
Balance at Dec. 31, 2004	$ 387,265	$ 183,932	$ (862)	$ (1,818)	$ 568,517	
Net Income	-	58,149	-	-	58,149	$ 58,149
Minimum pension liability adjustment, net of $59 of tax	-	-	-	(93)	(93)	(93)
Restricted stock amortizations	-	-	212	-	212	
Dividends paid on common stock	-	(36,376)	-	-	(36,376)	
Tax benefits from employee stock option plan	220	-	-	-	220	
Issuance of common stock	7,266	-	-	-	7,266	
Common stock repurchased	(14,945)	-	-	-	(14,945)	
Convertible debentures	3,999	-	-	-	3,999	
Common stock expense	-	(18)	-	-	(18)	
Balance at Dec. 31, 2005	383,805	205,687	(650)	(1,911)	586,931	$ 58,056
Net Income	-	63,415	-	-	63,415	$ 63,415
Minimum pension liability adjustment, net of $52 of tax	-	-	-	(81)	(81)	(81)
Recognition of non-qualified employee benefit plan liability, net of $232 of tax			(364)	(364)		
Restricted stock amortizations	298	-	-	-	298	
Dividends paid on common stock	-	(38,298)	-	-	(38,298)	
Tax benefits from employee stock option plan	317	-	-	-	317	
Stock-based compensation	555	-	-	-	555	
Restricted stock reclassification	(650)	-	650	-	-	
Issuance of common stock	2,773	-	-	-	2,773	
Common stock repurchased	(15,971)	-	-	-	(15,971)	
Common stock expense	-	(30)	-	-	(30)	
Balance at Dec. 31, 2006	371,127	230,774	-	(2,356)	599,545	$ 63,334
Net Income	-	74,497	-	-	74,497	$ 74,497
Change in unrealized loss from price risk management activities	-	-	-	(41)	(41)	(41)
Change in non-qualified employee benefit plan liability, net of $487 of tax	-	-	-	(1,232)	(1,232)	(1,232)
Amortization of non-qualified employee benefit plan liability, net of ($81) of tax	-	-	-	127	127	127
Restricted stock amortizations	285	-	-	-	285	
Dividends paid on common stock	-	(38,613)	-	-	(38,613)	
Tax benefits from employee stock option plan	536	-	-	-	536	
Stock-based compensation	2,094	-	-	-	2,094	
Issuance of common stock	2,180	-	-	-	2,180	
Common stock repurchased	(44,627)	-	-	-	(44,627)	
Balance at Dec. 31, 2007	$ 331,595	$ 266,658	$ -	$ (3,502)	$ 594,751	$ 73,351

See Notes to Consolidated Financial Statements.

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

Thousands (year ended December 31)	2007	2006	2005
Operating activities:			
Net income	$ 74,497	$ 63,415	$ 58,149
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	68,343	64,435	61,645
Deferred income taxes and investment tax credits	(5,252)	(16,440)	9,551
Undistributed earnings from equity investments	(130)	(191)	(57)
Deferred gas costs - net	38,665	20,752	2,577
Gain on sale of non-utility investments	(1,544)	(495)	-
Income from life insurance investments	(1,939)	(2,609)	(1,873)
Contributions to qualified defined benefit pension plans	-	-	(31,000)
Non-cash expenses related to qualified defined benefit pension plans	4,387	5,500	4,532
Deferred environmental expenditures	(8,842)	(6,675)	(9,132)
Deferred regulatory costs and other	(2,940)	14,533	3,243
Changes in working capital:			
Accounts receivable and accrued unbilled revenue - net	22,029	(3,722)	(40,262)
Inventories of gas, materials and supplies	(1,816)	8,033	(19,684)
Income taxes receivable	(122)	13,234	2,736
Prepayments and other current assets	(6,528)	2,952	(3,439)
Accounts payable	5,841	(21,708)	32,809
Accrued interest and taxes	(8,068)	8,511	2,504
Other current and accrued liabilities	7,059	(959)	6,767
Cash provided by operating activities	183,640	148,566	79,066
Investing activities:			
Investment in utility plant	(93,785)	(95,307)	(89,259)
Investment in non-utility property	(24,442)	(1,773)	(6,842)
Proceeds from sale of non-utility investments	2,628	2,517	3,001
Proceeds from life insurance	881	4,009	296
Contributions to non-utility equity investments	(5,413)	-	-
Other	2,652	(13)	796
Cash used in investing activities	(117,479)	(90,567)	(92,008)
Financing activities:			
Common stock issued, net of expenses	2,180	3,913	7,486
Common stock repurchased	(44,627)	(15,971)	(14,945)
Long-term debt issued	-	25,000	50,000
Long-term debt retired	(29,500)	(8,000)	(15,528)
Change in short-term debt - net	43,000	(26,600)	24,200
Cash dividend payments on common stock	(38,613)	(38,298)	(36,376)
Other	1,739	581	-
Cash (used in) provided by financing activities	(65,821)	(59,375)	14,837
Increase (decrease) in cash and cash equivalents	340	(1,376)	1,895
Cash and cash equivalents - beginning of period	5,767	7,143	5,248
Cash and cash equivalents - end of period	$ 6,107	$ 5,767	$ 7,143
Supplemental disclosure of cash flow information:			
Interest paid	$ 38,508	$ 39,294	$ 36,974
Income taxes paid	$ 56,215	$ 31,270	$ 28,479
Supplemental disclosure of non-cash financing activities:			
Conversions to common stock:			
7-1/4 % Series of Convertible Debentures	$ -	$ -	$ 3,999

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Organization and Principles of Consolidation

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), which primarily consist of our regulated gas distribution business and our regulated gas storage business, and other businesses which primarily consist of our wholly-owned subsidiary businesses including NNG Financial Corporation (Financial Corporation) and Gill Ranch Storage, LLC (Gill Ranch), and a joint venture in a natural gas transmission pipeline (See Note 2).

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

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

Use of Estimates

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

Industry Regulation

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

In applying SFAS No. 71, we capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the OPUC or WUTC in general rate case or other deferral proceedings, for example, our purchased gas adjustment (PGA) mechanism, to provide for recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge.

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At December 31, 2007 and 2006, the amounts deferred as regulatory assets and liabilities were as follows:

	Current		Non-Current	
Thousands	2007	2006	2007	2006
Regulatory assets:				
Unrealized loss on non-trading derivatives[1]	$ 14,788	$ 30,798	$ 3,758	$ 9,584
Income tax asset	-	-	68,649	67,141
Pension and other postretirement benefit obligations[2]	1,912	-	27,152	54,425
Environmental costs - paid[3]	-	-	27,956	19,113
Environmental costs - accrued but not yet paid[3]	-	-	35,098	8,760
Other[4]	898	711	13,325	5,748
Total regulatory assets	$ 17,598	$ 31,509	$ 175,938	$ 164,771
Regulatory liabilities:				
Gas costs payable[5]	$ 46,153	$ 737	$ 6,290	$ 13,041
Unrealized gain on non-trading derivatives[1]	2,903	-	324	-
Accrued asset removal costs	-	-	204,886	187,422
Other[4]	12,270	11,182	2,264	2,519
Total regulatory liabilities	$ 61,326	$ 11,919	$ 213,764	$ 202,982

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

2 Qualified pension plan and other postretirement costs are approved for regulatory deferral. Such amounts are recoverable in rates, including an interest component, when recognized in net periodic benefit cost (see Note 7).

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

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

5 A majority of gas costs deferred earn a rate of return or carrying charge.

We believe that continued application of SFAS No. 71 for regulated activities is appropriate and consistent with the current regulatory environment, and that all regulated assets and liabilities at December 31, 2007 and 2006 are recoverable or refundable through future utility rates. We annually review all regulatory assets for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of SFAS No. 71, then we would be required to write off the net unrecoverable balances against earnings.

New Accounting Standards

Adopted Standards

Accounting for Uncertainty in Income Taxes. On January 1, 2007, we adopted Financial Accounting Standards Board (FASB) Interpretation No. 48 (FIN 48), "Accounting for Uncertainty in Income Taxes, an Interpretation of FASB Statement No. 109," which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. As a result of the implementation of FIN 48, we recognized no change in our recorded assets or liabilities for unrecognized income tax benefits. Based on our analysis of all material tax positions taken, management believes the technical merits of these positions are justified and expects that the full amount of the deductions taken and associated tax benefits will be allowed.

FIN 48 requires the evaluation of a tax position as a two-step process. We must determine whether it is more likely than not that a tax position will be sustained upon examination, including the resolution of any related appeals or litigation processes, based on the technical merits of the position. If the tax position meets the "more likely than not" recognition threshold, then the tax benefit is measured and recorded at the largest amount that is greater than 50 percent likely of being realized upon effective settlement. The re-assessment of our tax positions in accordance with FIN 48 did not result in any material change to our financial condition, results of operations or cash flows.

FIN 48 prescribes that a company recognize the benefit of a tax position when it is effectively settled. In May 2007, FASB Staff Position (FSP) FIN 48-1, "Definition of Settlement in FASB Interpretation No. 48," was issued to provide guidance on how to determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. The provisions of FSP FIN 48-1 did not change the conclusions reached during our adoption of FIN 48.

We are subject to U.S. federal income taxes as well as several state and local income taxes. All of our U.S. federal income tax matters audited by the Internal Revenue Service through the 2004 tax year were concluded during 2006 with no material adjustments. Also, substantially all material state and local income tax matters are closed through the 2003 tax year. Based upon our assessment in connection with the adoption of FIN 48, we do not believe there are any tax positions taken that would not be fully sustained upon audit.

We have also assessed the classification of interest and penalties, if any, related to income tax matters. Pursuant to the application of FIN 48, we have made an accounting policy election to treat interest and penalties related to income tax matters, if any, as a component of income tax expense rather than other operating expenses. See Note 8.

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

Recent Accounting Pronouncements

Fair Value Measurements. In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which provides a common definition for the measurement of fair value for use in applying GAAP and in preparing financial statement disclosures. Most of SFAS No. 157 is effective as of the beginning of the first annual period after November 15, 2007, or January 1, 2008. However, implementation of the fair value measurement of liabilities applicable to us has been delayed until the beginning of the first annual period after November 15, 2008. This pronouncement replaces the definition of price used to determine fair value as the "price that would be received to sell an asset or paid to transfer a liability in an orderly transaction." To increase consistency and comparability, it also establishes a hierarchy of inputs used to calculate fair value, ranging from level one (observable) to level three inputs (unobservable).

New disclosures under SFAS No. 157 will primarily consist of:

- A description of the fair value measurements at the reporting date;
- A description of the inputs for fair value calculations;
- A description of the level of each input within the fair value hierarchy, segregated by input level;
- A tabular reconciliation for all level three inputs illustrating the total gains and losses, purchases or sales, and transfers into or out of level three;
- A tabular detail of the gains and losses for the period; and,
- A description of the valuation techniques used to measure fair value and a discussion of changes in valuation techniques, if any.

Adoption of SFAS No. 157 will require us to identify the inputs for our fair value calculations according to the fair value hierarchy, increase coordination with our external service providers and provide more detailed disclosure. Based on our preliminary assessment, the adoption of SFAS No. 157 is not expected to have a material effect on our financial condition, results of operations or cash flow.

Fair Value Option for Financial Assets and Liabilities. In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities," which permits entities to choose to measure many financial instruments and certain other items at fair value. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. Based on our preliminary evaluation, the adoption and implementation of SFAS No. 159 is not expected to have a material effect on our financial condition, results of operations or cash flow.

Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards. In November 2006, the Emerging Issues Task Force (EITF) issued EITF 06-11, "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards," which provides the accounting requirements for the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options, and how these benefits are charged to retained earnings under SFAS No. 123R, "Share Based Payment." EITF 06-11 is effective as of the beginning of the first annual period starting after December 15, 2007.

EITF 06-11 will require us to adjust our current accounting policy on the recognition of the income tax benefit received on dividends paid to employees. Based on our preliminary evaluation, the adoption of EITF 06-11 is not expected to have a material impact on our financial condition, results of operations or cash flow.

Plant and Property and Accrued Asset Removal Costs

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

Our provision for depreciation of utility property is computed under the straight-line, age-life method in accordance with independent engineering studies and as approved by regulatory authorities. The weighted average depreciation rate for utility plant in service was approximately 3.4 percent for each of the years ended December 31, 2007, 2006 and 2005, reflecting the approximate average economic life of the property.

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

Allowance for Funds Used During Construction

Certain additions to utility plant include AFUDC, which represents the net cost of borrowed or other funds used during construction and is calculated using actual current interest rates. If borrowings are less than the total costs of construction work in progress, then a composite rate of interest on all debt, shown as a reduction to interest charges, and a return on equity funds, shown as other income, is used to compute the AFUDC. While cash is not realized currently from AFUDC, it is realized in future years through increased revenues from rate recovery resulting from higher rate base and higher depreciation expense. Our composite AFUDC rates were 5.4 percent in 2007, 4.7 percent in 2006 and 3.1 percent in 2005.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand and highly liquid temporary investments with original maturity dates of three months or less. At December 31, 2007 and 2006, book overdrafts of $4.9 million and $3.7 million, respectively, were included within accounts payable.

Revenue Recognition and Accrued Unbilled Revenues

Utility revenues, derived primarily from the sale and transportation of gas, are recognized when the gas is delivered to and received by the customer. Revenues include accruals for gas delivered but not yet billed to customers based on estimates of gas deliveries from meter reading dates to month end (accrued unbilled revenues). Accrued unbilled revenues are dependent upon a number of factors that require management’s judgment, including total gas receipts and deliveries, customer use and weather. Accrued unbilled revenues are reversed the following month when actual billings occur. Our accrued unbilled revenues at December 31, 2007 and 2006 were $78.0 million and $87.5 million, respectively.

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

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

Accounts Receivable and Allowance for Uncollectible Accounts

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

Inventories

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

Derivatives

In accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities" (collectively referred to as SFAS No. 133), we measure derivatives at fair value and recognize them as either assets or liabilities on the balance sheet. SFAS No. 133 requires that changes in the fair value of a derivative be recognized currently in earnings unless specific hedge accounting criteria are met. SFAS No. 133 provides an exception for contracts intended for normal purchases and normal sales for which physical delivery is probable. In addition, certain derivatives contracts are approved by regulatory authorities for recovery or refund through customer rates. Accordingly, the changes in fair value of these contracts are deferred as regulatory assets or liabilities pursuant to SFAS No. 71. Derivatives contracts entered into for core utility customer requirements after the PGA rate has been set are subject to the PGA incentive sharing mechanism, whereby 67 percent of the changes in fair value are deferred as regulatory assets or liabilities and the remaining 33 percent is recorded to the income statement for derivatives that do not qualify for hedge accounting, and to Other Comprehensive Income for hedges that do qualify for hedge accounting (see Note 11).

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

Revenue Taxes

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

Income Tax Expense

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

SFAS No. 109 also requires recognition of deferred income tax assets and liabilities for temporary differences where regulators prohibit deferred income tax treatment for ratemaking purposes. We have recorded a deferred tax liability equivalent to $68.6 million and $67.1 million at December 31, 2007 and 2006, respectively, to recognize future taxes payable resulting from transactions that have previously been reflected in the financial statements for these temporary differences. Regulatory assets or liabilities corresponding to such additional deferred income tax assets or liabilities may be recorded to the extent we believe they will be recoverable from or payable to customers through the ratemaking process. Pursuant to SFAS No. 71, a corresponding regulatory asset has been recorded which represents the probable future revenue that will result from inclusion in rates charged to customers of taxes which will be paid in the future. The probable future revenue to be recorded takes into consideration the additional future taxes which will be generated by that revenue. Amounts applicable to income taxes due from customers primarily represent differences between the book and tax basis of net utility plant in service and actual removal costs incurred.

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

Other Income and Expense—Net

Other income and expense – net consists of interest income, gain on sale of investments, investment income of Financial Corporation, investment expenses of our proposed pipeline project and other miscellaneous income from merchandise sales, rents, leases and other items.

Thousands	2007	2006	2005
Gains from company-owned life insurance	$ 1,939	$2,609	$ 1,856
Interest income	537	363	403
Earnings from equity investments of Financial Corporation	130	191	57
Gain on sale from equity investments	1,544	-	-
Other non-operating expenses	(2,789)	(852)	(1,393)
Net interest on certain deferred regulatory accounts	84	(177)	282
	$ 1,445	$2,134	$ 1,205

Earnings Per Share

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

Thousands, except per share amounts	2007	2006	2005
Net income	$74,497	$63,415	$58,149
Average common shares outstanding - basic	26,821	27,540	27,564
Stock based compensation	174	117	57
Average common shares outstanding - diluted	26,995	27,657	27,621
Earnings per share of common stock - basic	$ 2.78	$ 2.30	$ 2.11
Earnings per share of common stock - diluted	$ 2.76	$ 2.29	$ 2.11

For the years ended December 31, 2007, 2006 and 2005, 442 shares,105,600 shares and 6,000 shares, respectively, represent the number of stock options which were excluded from the calculation of diluted earnings per share because the effect was antidilutive.

Stock-Based Compensation

We periodically provide stock-based compensation to employees in the form of stock options and other incentive awards. As required by SFAS No. 123R, "Share Based Compensation," we recognize the fair value of all share-based payments as compensation expense in the financial statements. Prior to January 1, 2006, as permitted by SFAS No. 123, we applied APB Opinion No. 25, "Accounting for Stock Issued to Employees," to account for stock-based compensation. Accordingly, prior to January 1, 2006, we did not recognize compensation expense for the fair value of our stock option grants. We implemented SFAS 123R effective January1, 2006 by applying the modified prospective transition method. The impact on net income of this new standard, had it been adopted in 2005, is reflected in the pro forma amounts in Note 4.

2. CONSOLIDATED SUBSIDIARY OPERATIONS AND SEGMENT INFORMATION:

At December 31, 2007, we had two direct wholly-owned subsidiaries, Financial Corporation and Gill Ranch Storage, LLC.

Our core business segment is the local gas distribution segment, also referred to as the "utility," which involves the distribution and sale of natural gas. Another business segment, "gas storage," represents natural gas storage services provided to intrastate and interstate customers, and includes asset optimization services under a contract with an independent energy marketing company. The remaining business segment, "other," primarily consists of wholly-owned subsidiaries, Financial Corporation and Gill Ranch, as well as various other non-utility investments, including an investment in a leveraged aircraft lease and our equity investment in a proposed natural gas pipeline project with TransCanada Gas Transmission Northwest (GTN). See Note 9.

Gas Storage

The gas storage business segment is primarily made up of underground natural gas storage services that we provide to large intra- and inter-state customers using our owned storage capacity at Mist that has been developed in advance of core utility customers' requirements. In Oregon, we retain 80 percent of the income before tax from these services and credit the remaining 20 percent to a deferred regulatory account for sharing with core utility customers. For each of the years ended December 31, 2007, 2006 and 2005, this business segment derived a majority of its revenues from multi-year contracts with less than 10 customers. The largest of these customers is served under a long-term contract.

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

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Other

In October 2007, Financial Corporation sold its investments in two wind power electric generating projects for $2.1 million, which resulted in an after-tax net gain on sale of $0.9 million. In addition, in December 2007, one low-income housing project investment reached the end of the contract period and our partnership interest was transferred pursuant to the original terms of the agreement.

Financial Corporation holds certain non-utility financial investments, but its assets primarily consist of an active, wholly-owned subsidiary which owns a 10 percent interest in an 18-mile interstate natural gas pipeline. Our capacity on this pipeline is contracted to NW Natural's utility operations. Financial Corporation's remaining assets totaled $1.4 million and $2.6 million at December 31, 2007 and 2006, respectively.

At December 31, 2006, we reclassified to current assets our net investment of $5.3 million in a Boeing 737-300 airplane leased to Continental Airlines. The original lease term expired in September 2007, and the aircraft lease was extended at the option of the lessee for 12 months. We are currently in negotiations to sell the airplane and expect it to be sold during 2008.

Segment Information Summary

The following table presents summary financial information about the reportable segments for 2007, 2006 and 2005. Inter-segment transactions are insignificant.

Thousands	Utility	Gas Storage	Other	Total
2007				
Net operating revenues	$ 351,875	$ 16,999	$ 168	$ 369,042
Depreciation and amortization	67,410	933	-	68,343
Income (loss) from operations	140,434	14,953	(464)	154,923
Income from financial investments	1,939	-	1,674	3,613
Net income	64,938	8,742	817	74,497
Total assets at Dec. 31, 2007	1,940,844	59,427	13,912	2,014,183
2006				
Net operating revenues	$ 327,267	$ 12,761	$ 148	$ 340,176
Depreciation and amortization	63,552	883	-	64,435
Income from operations	126,366	9,870	526	136,762
Income from financial investments	2,609	-	191	2,800
Net income	56,653	5,982	780	63,415
Total assets at Dec. 31, 2006	1,912,021	35,970	8,865	1,956,856
2005				
Net operating revenues	$ 315,248	$ 9,609	$ 136	$ 324,993
Depreciation and amortization	60,935	710	-	61,645
Income (loss) from operations	118,794	8,158	(5)	126,947
Income from financial investments	1,856	-	57	1,913
Net income	52,759	4,557	833	58,149

3. CAPITAL STOCK:

Common Stock

As of December 31, 2006 and 2007, we had 60,000,000 common shares authorized.

At December 31, 2007, we had reserved 223,033 shares of common stock for issuance under the Employee Stock Purchase Plan, 666,537 shares under our Dividend Reinvestment and Direct Stock Purchase Plan and 1,393,150 shares under our Restated Stock Option Plan (see Note 4).

In connection with the restatement of our Restated Articles of Incorporation, effective May 31, 2006, the par value of our common stock was eliminated. As a result, at December 31, 2007 and 2006, our "common stock" and "premium on common stock" account balances are reflected on the balance sheet as "common stock."

Stock Repurchase Program

Our publicly announced stock repurchase program allows us to purchase up to 2.8 million shares, or up to $100.0 million in total, of our common stock in the open market or through privately negotiated transactions. We repurchased a total of 963,428, 395,500 and 410,200, shares under this program in 2007, 2006, and 2005, respectively. In addition, during the first half of 2007, we completed our voluntary oddlot share buyback program, which resulted in a net repurchase of 10,188 shares.

Restated Stock Option Plan

There are 2,400,000 shares authorized for option grants under the Restated Stock Option Plan. At December 31, 2007, options on 1,035,400 shares were available for grant and options on 357,750 shares were outstanding.

Convertible Debentures

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

Summary of Changes in Common Stock

The following table shows the changes in the number of shares of our common stock issued and outstanding and the premium on common stock for the years 2007, 2006 and 2005:

	Shares	Premium on common stock (thousands)
Balance, Dec. 31, 2004	27,546,720	$ 300,034
Sales to employees	30,896	741
Sales to stockholders	113,925	3,741
Exercise of stock options - net	97,068	2,241
Conversion of convertible debentures to common	200,887	3,360
Repurchase	(410,200)	(13,646)
Balance, Dec. 31, 2005	27,579,296	$ 296,471
Sales to employees	31,397	-
Exercise of stock options - net	68,548	285
Repurchase	(395,500)	(1,461)
Change to no-par common stock	-	(295,295)
Balance, Dec. 31, 2006	27,283,741	$ -
Sales to employees	21,373	n/a
Exercise of stock options - net	75,850	n/a
Repurchase	(973,616)	n/a
Balance, Dec. 31, 2007	26,407,348	$ -

4. STOCK-BASED COMPENSATION:

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

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

At December 31, 2007, 299,721 shares of common stock were available for award under the LTIP, assuming that outstanding performance based grants are awarded at the target level. The LTIP stock awards are compensatory awards for which compensation expense is recognized based on the market value of performance shares earned, or a pro rata amortization over the vesting period for the outstanding restricted stock awards.

Performance-based Stock Awards. Since the LTIP's inception in 2001 through December 31, 2007, performance-based stock awards have been granted annually based on three-year performance periods. At December 31, 2007, certain performance-based stock award measures had been achieved for the 2005-07 award period. Accordingly, participants are estimated to receive 66,666 shares of common stock and a dividend equivalent cash payment equal to the number of shares of common stock received on the award payout multiplied by the aggregate cash dividends paid per share during the performance period. At December 31, 2006, certain performance-based stock award measures had been achieved for the 2004-06 award period and participants received 40,446 shares of common stock plus the applicable dividend equivalent cash payment, resulting in $0.8 million in cash for taxes or deferral into the deferred compensation plan. During 2007, we accrued and expensed $0.6 million related to the 2005-07 performance-based stock award, and on a cumulative basis we accrued a total $2.0 million related to the 2005-07 performance period. In 2006, we accrued and expensed $0.9 million related to the 2004-06 performance-based stock award, and on a cumulative basis we accrued a total of $1.7 million related to the 2004-06 performance period.

At December 31, 2007, the aggregate number of performance-based shares granted and outstanding at the threshold, target and maximum levels were as follows:

Year Awarded	Performance Period	Performance Share Awards Outstanding		
		Threshold	Target	Maximum
2006	2006-08	7,536	39,665	79,330
2007	2007-09	7,980	42,000	84,000
	Total	15,516	81,665	163,330

The threshold level estimates future payout assuming the minimum award payable other than no payout for each component of the formula in the LTIP. For each of these performance periods, awards will be based on total shareholder return relative to a peer group of gas distribution companies over the three-year performance period and on performance results achieved relative to specific core and non-core strategies. Compensation expense is recognized in accordance with SFAS No. 123R, based on performance levels achieved and an estimated fair value using a Black-Scholes or binomial model. The weighted-average per share grant date fair value of unvested shares at December 31, 2007 and 2006 was $25.45 and $30.65, respectively. The weighted-average per share grant date fair value of shares vested during the year was $44.95 and granted during the year was $31.32. In 2007, under these LTIP grants we accrued $2.7 million and expensed $2.3 million as compensation, while in 2006, we accrued and expensed $1.0 million.

Restricted Stock Awards. Restricted stock awards also have been granted under the LTIP. A restricted stock award was granted in 2004 consisting of 5,000 shares that will vest ratably over the period 2005-09, and a restricted stock award was granted in 2006 consisting of 6,500 shares that will vest ratably over the period 2007-09. A total of 5,167 restricted stock award shares were vested at December 31, 2007. Compensation expense is recognized ratably over the vesting period.

Restated Stock Option Plan. The Restated SOP authorizes an aggregate of 2,400,000 shares of common stock for issuance as incentive or non-statutory stock options. These options may be granted only to officers and key employees designated by a committee of our Board of Directors. All options are granted at an option price not less than the market value on the date of grant and may be exercised for a period not exceeding 10 years from the date of grant.

Option holders may exchange shares they have owned for at least six months, at the current market price, to purchase shares at the option price. We use original issue shares upon exercise of options under the plan. See Note 3.

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

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

Pro Forma Effect of Stock-Based Options and ESPP:

Thousands, except per share amounts	2005
Net income as reported	$58,149
Add: Stock-based compensation expense included in reported net income - net of related tax effects	613
Deduct: Pro forma stock-based compensation expense determined under the fair value based method - net of related tax effects	(940)
Pro forma earnings applicable to common stock	$57,822
Basic earnings per share	
As reported	$ 2.11
Pro forma	$ 2.10
Diluted earnings per share	
As reported	$ 2.11
Pro forma	$ 2.09

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

	2007	2006	2005
Risk-free interest rate	4.7%	4.5%	4.2%
Expected life (in years)	6.2	6.2	7.0
Expected market price volatility factor	17.2%	22.8%	24.6%
Expected dividend yield	3.2%	4.0%	3.6%
Forfeiture rate	4%	3%	n/a
Weighted average grant date fair value	$7.66	$6.29	$7.85
Present value of options granted	$33.38	$26.00	$27.87

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

Information regarding the Restated SOP's activity for the three years ended December 31, 2007 is summarized as follows:

	Option Shares	Price per Share Range	Price per Share Weighted - Average Exercise Price	Intrinsic Value (In millions)
Balance outstanding, Dec. 31, 2004	431,470	$20.25 - 32.02	$ 28.38	n/a
Granted	9,000	34.95 - 38.30	37.18	n/a
Exercised	(121,170)	20.25 - 31.34	26.59	$ 1.2
Forfeited	(10,800)	27.60 - 31.34	30.79	n/a
Balance outstanding, Dec. 31, 2005	308,500	20.25 - 38.30	29.26	n/a
Granted	97,800	34.29	34.29	n/a
Exercised	(69,300)	20.25 - 31.34	27.15	0.8
Forfeited	(3,000)	31.34 - 34.29	32.52	n/a
Balance outstanding, Dec. 31, 2006	334,000	20.25 - 38.30	31.14	n/a
Granted	100,600	44.48	44.48	n/a
Exercised	(75,850)	20.25 - 34.95	28.73	1.4
Forfeited	(1,000)	44.48	44.48	n/a
Balance outstanding, Dec. 31, 2007	357,750	$20.25 - 44.48	$ 35.36	$ 4.8
Shares available for grant				
Dec. 31, 2005	1,229,800			
Shares available for grant				
Dec. 31, 2006	1,135,000			
Shares available for grant				
Dec. 31, 2007	1,035,400			

In the year ended December 31, 2007, cash of $2.7 million was received for option shares exercised and a $0.5 million related tax benefit was realized. The total fair value of options that vested was $0.2 million in 2007 and $0.4 million in both 2006 and 2005.

The following table summarizes additional information about stock options outstanding and exercisable at December 31, 2007:

	Outstanding		Exercisable			
Range of Exercise Prices	Stock Options	Weighted-Average Remaining Life in Years	Stock Options	(In millions) Aggregate Intrinsic Value	Weighted-Average Exercise Price	Weighted-Average Remaining Life in Years
$20.25 - 44.48	357,750	7.35	193,675	$3.4	$31.15	6.2

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

Thousands	2007	2006
Operations and maintenance expense	$ 2,986	$2,304
Stock-based compensation effect on income before taxes	2,986	2,304
Income taxes	(1,165)	(898)
Net stock-based compensation effect on net income	$ 1,821	$1,406
Amounts capitalized	$ 479	$ 407

As of December 31, 2007, there was $0.6 million of unrecognized compensation cost related to the unvested portion of outstanding stock option awards expected to be recognized over a period extending through 2010.

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

Prior to the latter amendment to the NEDSCP, if non-employee directors elected to receive their awards in stock, approximately $100,000 worth of common stock was awarded upon joining the Board. These stock awards were subject to vesting and to restrictions on sale and transferability. The shares vested in monthly installments over the five calendar years following the award. On January 1 of each year following the initial award, non-employee directors who elected to receive their awards in stock were awarded an additional $20,000 worth of restricted stock, which vested in monthly installments in the fifth year following the award (after the previous award had fully vested). We hold the certificates for the restricted shares until the non-employee director ceases to be a director. Participants receive all dividends and have full voting rights on both vested and unvested shares. All awards vest immediately upon the death of a director or upon a change in control of the Company. Any unvested shares are considered to be unearned compensation, and thus are forfeited if the recipient ceases to be a director. The shares were purchased in the open market at the time of the award. During 2006, 7,848 shares vested under the plan and no forfeitures occurred. At December 31, 2007, 5,235 shares remain unvested, all of which are scheduled to vest by December 31, 2008. The weighted-average grant-date fair value of unvested shares at December 31, 2007 and 2006 was $30.60 and $28.92, respectively.

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

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5. LONG-TERM DEBT:

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

The maturities on the long-term debt outstanding, for each of the 12-month periods through December 31, 2012 amount to: $5 million in 2008; none in 2009; $35 million in 2010; $10 million in 2011; and $40 million in 2012. Holders of certain long-term debt have put options that, if exercised, would accelerate the maturities by $20 million in both 2008 and 2009.

Thousands (December 31)	2007	2006	2005
Medium-Term Notes			
First Mortgage Bonds:			
6.05% Series B due 2006[1]	$ -	$ -	$ 8,000
6.31 % Series B due 2007[2]	-	20,000	20,000
6.80 % Series B due 2007[3]	-	9,500	9,500
6.50% Series B due 2008	5,000	5,000	5,000
4.11% Series B due 2010	10,000	10,000	10,000
7.45% Series B due 2010	25,000	25,000	25,000
6.665% Series B due 2011	10,000	10,000	10,000
7.13% Series B due 2012	40,000	40,000	40,000
8.26% Series B due 2014	10,000	10,000	10,000
4.70% Series B due 2015	40,000	40,000	40,000
5.15% Series B due 2016	25,000	25,000	-
7.00% Series B due 2017	40,000	40,000	40,000
6.60% Series B due 2018	22,000	22,000	22,000
8.31% Series B due 2019	10,000	10,000	10,000
7.63% Series B due 2019	20,000	20,000	20,000
9.05% Series A due 2021	10,000	10,000	10,000
5.62% Series B due 2023	40,000	40,000	40,000
7.72% Series B due 2025	20,000	20,000	20,000
6.52% Series B due 2025	10,000	10,000	10,000
7.05% Series B due 2026	20,000	20,000	20,000
7.00% Series B due 2027	20,000	20,000	20,000
6.65% Series B due 2027	20,000	20,000	20,000
6.65% Series B due 2028	10,000	10,000	10,000
7.74% Series B due 2030	20,000	20,000	20,000
7.85% Series B due 2030	10,000	10,000	10,000
5.82% Series B due 2032	30,000	30,000	30,000
5.66% Series B due 2033	40,000	40,000	40,000
5.25% Series B due 2035	10,000	10,000	10,000
	517,000	546,500	529,500
Less long-term debt due within one year	5,000	29,500	8,000
Total long-term debt	$ 512,000	$ 517,000	$ 521,500

(1) Redeemed at maturity in June 2006.

(2) Redeemed at maturity in March 2007.

(3) Redeemed at maturity in May 2007.

No long-term debt was issued during 2007. In 2006, we issued and sold $25 million of 5.15% Series B secured Medium Term Notes (MTNs) due 2016. Proceeds from this sale were used, in part, to repay short-term debt and fund our ongoing utility construction program.

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

6. NOTES PAYABLE AND CREDIT FACILITIES:

Our primary source of short-term funds is from the sale of commercial paper notes payable. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas purchases, gas inventories and accounts receivable, short-term debt is used temporarily to fund capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by a committed credit facility (see below). At December 31, 2007 and 2006, the amounts and average interest rates of commercial paper debt outstanding were $143.1 million and 4.4 percent and $100.1 million and 5.3 percent, respectively.

In May 2007, we entered into a credit agreement for unsecured revolving loans totaling $250 million, replacing the prior $200 million bilateral credit agreements which were terminated. The new credit facility is available and committed for a term of five years expiring on May 31, 2012, which may be extended for additional one-year periods thereafter subject to lender approval. The credit facility allows us to request increases in the total commitment amount, up to a maximum amount of $400 million. The credit facility also permits the issuance of letters of credit in an aggregate amount up to the applicable total borrowing commitment. The credit facility continues to be used primarily as back-up credit support for the notes payable issued under our commercial paper program. Commercial paper borrowing provides the liquidity to meet our working capital and interim financing requirements. Under the terms of the credit facility, we pay upfront fees, annual commitment fees and administrative agent fees, but we are not required to maintain compensating bank balances. The interest rates on outstanding loans, if any, under the credit agreement are based on our long-term unsecured debt ratings and on then-current market interest rates. All principal and unpaid interest under the credit facility is due and payable on May 31, 2012, subject to extensions if any. There were no outstanding balances on this credit facility at December 31, 2007 or on prior credit facilities at December 31, 2006.

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

The credit facility also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70 percent or less. Failure to comply with this covenant would entitle the lenders to terminate their lending commitments and to accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at December 31, 2007, with an indebtedness to total capitalization ratio of 52.7 percent. Our previous credit agreements required us to maintain an indebtedness to total capitalization ratio of 65 percent or less, which we were in compliance with at December 31, 2006.

7. PENSION AND OTHER POSTRETIREMENT BENEFITS:

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

The following table provides a reconciliation of the changes in benefit obligations and fair value of plan assets, as applicable, for the pension and other postretirement benefit plans over the three-year period ended December 31, 2007, and a summary of the funded status and amounts recognized in the consolidated balance sheets using measurement dates of December 31, 2007, 2006 and 2005:

	Postretirement Benefits					
	Pension Benefits			Other Benefits		
Thousands	2007	2006	2005	2007	2006	2005
Reconciliation of change in benefit obligation:						
Obligation at January 1	$ 269,410	$ 267,854	$ 222,948	$ 22,436	$ 20,398	$ 22,729
Service cost	8,708	7,745	6,322	505	555	767
Interest cost	16,057	14,901	13,203	1,293	1,184	1,248
Expected benefits paid	(15,924)	(13,183)	(12,866)	(1,299)	(1,015)	(1,173)
Plan amendments	3,887	-	1,408	-	15	2,384
Change in assumptions	(23,916)	(9,208)	31,642	(645)	133	2,215
Net actuarial (gain) or loss	2,339	1,301	5,197	(104)	1,166	(7,772)
Obligation at December 31	$ 260,561	$ 269,410	$ 267,854	$ 22,186	$ 22,436	$ 20,398
Reconciliation of change in plan assets:						
Fair value of plan assets at January 1	$ 236,518	$ 218,555	$ 186,787	$ -	$ -	$ -
Actual return on plan assets	19,658	30,088	12,558	-	-	-
Employer contributions	1,166	1,058	32,076	1,298	1,015	1,173
Benefits paid	(15,924)	(13,183)	(12,866)	(1,298)	(1,015)	(1,173)
Fair value of plan assets at December 31	$ 241,418	$ 236,518	$ 218,555	$ -	$ -	$ -
Funded status:						
Funded status at December 31	$ (19,143)	$ (32,892)	$ (49,299)	$ (22,186)	$ (22,436)	$ (20,398)
Unrecognized transition obligation	-	-	-	2,058	2,469	2,880
Unrecognized prior service cost	8,212	5,512	6,492	1,866	2,063	2,243
Unrecognized net actuarial loss	20,995	45,862	69,766	1,514	2,288	988
Net amount recognized	$ 10,064	$ 18,482	$ 26,959	$ (16,748)	$ (15,616)	$ (14,287)

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," which required balance sheet recognition of the overfunded or underfunded status of pension and other postretirement benefit plans. We adopted SFAS No. 158 effective December 31, 2006. For pension plans, the liability is based on the projected benefit obligation. Under SFAS No. 158, any actuarial gains and losses, prior service costs and transition assets or obligations that were not recognized under previous accounting standards must be recognized in accumulated other comprehensive income (AOCI) under common stock equity, net of tax, until they are amortized as a component of net periodic benefit cost. We consider the recognition of the underfunded status of the qualified defined benefit plans and postretirement benefit plans to be subject to regulatory deferral under SFAS No. 71. The unrecognized net gains and losses, prior service costs and transition obligations relating to our qualified defined benefit pension and postretirement benefit plans are recognized as regulatory assets. An estimated $1.9 million for the qualified plans, consisting of $1.4 million of prior service costs, transition obligations of $0.4 million, and negligible actuarial gains, will be amortized from the regulatory asset account to net periodic benefit cost in 2008. The gains and losses, prior service costs and transition obligations related to our non-qualified supplemental pension plans are recognized in AOCI, net of tax, under common stock equity because these expenses are not the basis for regulatory recovery; however, these amounts are not material. In 2008, an estimated $0.4 million consisting of actuarial gains of $0.4 million and negligible prior service costs for the non-qualified plans will be amortized from AOCI to net periodic benefit cost.

Our qualified defined benefit pension plans had an aggregate projected benefit obligation of $243.1 million, $255.5 million and $254.4 million at December 31, 2007, 2006 and 2005, respectively, and the fair value of plan assets was $241.4 million, $236.5 million and $218.6 million, respectively. Changes in valuation assumptions impact our projected benefit obligations. The projected benefit obligations at December 31, 2007 decreased $23.9 million due to an increase in the discount rate assumptions and increased by $3.4 million due to an increase in the benefit payments for certain retirees. The projected benefit obligations at December 31, 2006 decreased by $9.3 million, reflecting the increase in the discount rate assumptions, and increased by $0.3 million, reflecting updates in retirement and withdrawal rates for actual experience. The combination of investment returns and future cash contributions by the company is expected to provide sufficient funds to cover all future benefit obligations of the plans.

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

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

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

Our pension plan asset allocation at December 31, 2007 and 2006, and the target allocation and expected long-term rate of return by asset category, are as follows:

Asset Category	Percentage of Plan Assets Dec. 31, 2007	Percentage of Plan Assets Dec. 31, 2006	Target Allocation	Expected Long-term Rate of Return
US Large Cap Equity	18.1%	19.2%	20%	8.50%
US Small/Mid Cap Equity	13.1%	13.9%	15%	9.50%
Non-US Equity	24.9%	23.5%	20%	8.75%
Fixed Income	13.3%	15.6%	15%	5.50%
Real Estate	8.9%	7.7%	8%	7.75%
Absolute Return Strategy	16.3%	14.3%	15%	9.00%
Real Return Strategy	5.4%	5.8%	7%	7.75%
Weighted Average				8.25%

Our non-qualified supplemental defined benefit pension plans' benefit obligations were $17.5 million, $13.9 million and $13.5 million at December 31, 2007, 2006 and 2005, respectively. These plans are not subject to regulatory deferral and the changes in actuarial gains and losses, prior service costs and transition assets or obligations are recognized in AOCI under common stock equity, net of tax, until they are amortized as a component of net periodic benefit cost. Although the plans are unfunded plans with no plan assets due to their nature as non-qualified plans, we indirectly fund our obligations with company- and trust-owned life insurance.

Our plans for providing postretirement benefits other than pensions also are unfunded plans, but are subject to regulatory deferral. The gains and losses, prior service costs and transition assets or obligations for these plans were recognized as a regulatory asset. The accumulated postretirement benefit obligation for those plans was $22.2 million, $22.4 million and $20.4 million at December 31, 2007, 2006 and 2005, respectively.

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

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The following tables provide the components of net periodic benefit cost for the qualified and non-qualified pension and other postretirement benefit plans for the years ended December 31, 2007, 2006 and 2005 and the assumptions used in measuring these costs and benefit obligations:

	Pension Benefits			Other Postretirement Benefits		
Thousands	2007	2006	2005	2007	2006	2005
Service cost	$ 8,708	$ 7,745	$ 6,322	$ 505	$ 556	$ 767
Interest cost	16,057	14,901	13,203	1,293	1,184	1,248
Expected return on plan assets	(18,490)	(17,611)	(14,449)	-	-	-
Amortization of transition obligations	-	-	-	411	411	411
Amortization of prior service costs	1,188	979	1,077	197	195	142
Amortization of net loss	2,123	3,520	2,082	25	1	173
Net periodic benefit cost	$ 9,586	$ 9,534	$ 8,235	$ 2,431	$ 2,347	$ 2,741
Assumptions for net periodic benefit cost:						
Discount rate	6.0%-6.05%	5.75%	6.00%	5.91%	5.75%	6.00%
Rate of increase in compensation	4.0%-5.0%	4.0%-5.0%	4.0%-5.0%	n/a	n/a	n/a
Expected long-term rate of return	8.25%	8.25%	8.25%	n/a	n/a	n/a
Assumptions for funded status:						
Discount rate	6.76%-6.87%	6.0%-6.05%	5.75%	6.56%	5.91%	5.75%
Rate of increase in compensation	4.0%-5.0%	4.0%-5.0%	4.0%-5.0%	n/a	n/a	n/a
Expected long-term rate of return	8.25%	8.25%	8.25%	n/a	n/a	n/a

The assumed annual increase in trend rates used in measuring other postretirement benefits as of December 31, 2007 were 8 percent for medical and 11 percent for prescription drugs. Medical costs were assumed to decrease gradually each year to a rate of 4.50 percent by 2013, while prescription drug costs were assumed to decrease gradually each year to a rate of 4.50 percent by 2014.

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

Thousands	1% Increase	1% Decrease
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$ 26	$ (23)
Effect on health care cost component of the accumulated postretirement benefit obligation	$ 277	$ (250)

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The following table provides information regarding employer contributions and benefit payments for the two qualified pension plans, the non-qualified pension plans and the other postretirement benefit plans for the years ended December 31, 2007 and 2006, and estimated future payments:

Thousands				
Employer Contributions by Plan Year		Pension Benefits		Other Benefits
2006	$	1,527	$	1,015
2007		1,606		1,298
2008 (estimated)		1,703		1,794
Benefit Payments				
2005	$	12,866	$	1,173
2006		13,183		1,015
2007		15,924		1,298
Estimated Future Payments				
2008	$	14,809	$	1,794
2009		15,522		1,823
2010		16,623		1,887
2011		17,085		1,978
2012		17,897		1,960
2013-2017		100,776		10,183

Our RKSP is a qualified defined contribution plan under Internal Revenue Code Section 401(k). We also have non-qualified deferred compensation plans for eligible officers and senior managers. These plans are designed to enhance the retirement program of employees and to assist them in strengthening their financial security by providing an incentive to save and invest regularly. Our matching contributions to these plans totaled $1.9 million in 2007, $1.8 million in 2006, and $1.7 million in 2005. The RKSP includes an Employee Stock Ownership Plan.

In addition, we make contributions on behalf of each union employee to the Western States Office and Professional Employees Pension Fund, a multi-employer plan. Our contributions totaled $0.4 million in 2007 and $0.5 million in both 2006 and 2005.

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8. INCOME TAXES:

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

Thousands, except percentages	2007	2006	2005
Income taxes at federal statutory rate	$41,495	$34,877	$31,804
Increase (decrease):			
Current state income tax, net of federal tax benefit	4,566	3,655	2,913
Federal income tax credits	-	-	(210)
Amortization of investment and energy tax credits	(881)	(994)	(956)
Differences required to be flowed-through by regulatory commissions	(704)	(704)	(704)
Gains on company and trust-owned life insurance	(679)	(913)	(650)
Other - net	244	155	187
Reversal of amounts provided in prior years	19	158	336
Total provision for income taxes	$44,060	$36,234	$32,720
Federal statutory tax rate	35.0%	35.0%	35.0%
Increase (decrease):			
Current state income tax, net of federal tax benefit	3.9%	3.7%	3.2%
Federal income tax credits	0.0%	0.0%	-0.2%
Amortization of investment and energy tax credits	-0.7%	-1.0%	-1.1%
Differences required to be flowed-through by regulatory commissions	-0.6%	-0.7%	-0.8%
Gains on company and trust-owned life insurance	-0.6%	-0.9%	-0.7%
Other - net	0.2%	0.2%	0.2%
Reversal of amounts provided in prior years	0.0%	0.1%	0.4%
Effective tax rate	37.2%	36.4%	36.0%

The provision for income taxes consists of the following:

Thousands	2007	2006	2005
Current tax expense	$ 48,850	$ 52,621	$ 23,034
Deferred tax expense (benefit)	(3,909)	(15,393)	10,642
Deferred investment and energy tax credits	(881)	(994)	(956)
Total provision for income taxes	$ 44,060	$ 36,234	$ 32,720
Total income taxes paid	$56,215	$31,270	$28,479

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

Thousands	2007	2006	2005
Regulated utility:			
Federal			
Current	$ 36,805	$ 40,979	$ 17,848
Deferred	(3,287)	(12,472)	8,691
Deferred investment and energy tax credits	(713)	(756)	(784)
	32,805	27,751	25,755
State			
Current	6,782	7,490	1,649
Deferred	(569)	(2,338)	2,855
	6,213	5,152	4,504
Total charged to regulated utility	39,018	32,903	30,259
Non-regulated business segments:			
Federal			
Current	4,281	3,806	3,581
Deferred	61	(714)	(1,189)
Deferred investment and energy tax credits	(168)	(238)	(172)
	4,174	2,854	2,220
State			
Current	982	346	(44)
Deferred	(114)	131	285
	868	477	241
Total charged to non-regulated business segments	5,042	3,331	2,461
Total provision for income taxes	$ 44,060	$ 36,234	$ 32,720

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

Thousands	2007	2006
Deferred tax liabilities (assets)		
Utility plant and equipment	$ 155,832	$ 150,648
Regulatory Adjustment for Income Taxes Paid	2,356	-
Utility other deferred tax differences	477	-
Non-regulated deferred tax differences	3,923	3,893
Deferred tax liabilities	162,588	154,541
Utility regulatory balances	(25,973)	(10,039)
Utility other deferred tax differences	-	(4,053)
Deferred tax assets	(25,973)	(14,092)
Deferred tax liabilities - net	136,615	140,449
Regulatory income tax assets	68,649	67,141
Change in employee post retirement benefit plan liability	(2,118)	(1,413)
Deferred income taxes	203,146	206,177
Deferred investment tax credits	3,194	3,907
Deferred income taxes and investment tax credits	$ 206,340	$ 210,084

We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2007.

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

Thousands	2007
Deferred tax expense (benefit), above	$(3,909)
Increase in differences required to be flowed-through	1,508
Decrease in minimum pension liability included in AOCI	(705)
Decrease in deferred taxes associated with asset held for sale	243
Decrease in deferred investment tax credits	(881)
Change in deferred income tax accounts	$(3,744)

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

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

9. PROPERTY AND INVESTMENTS:

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

	2007		2006	
Thousands, except percentages	Amount	Weighted Average Depreciation Rate	Amount	Weighted Average Depreciation Rate
Transmission and distribution	$1,735,934	3.3%	$1,657,466	3.3%
Utility storage	112,984	2.6%	110,721	2.6%
General	96,612	3.0%	92,946	2.6%
Intangible and other	71,044	8.8%	68,088	8.6%
Gas stored long-term	14,232	0.0%	12,850	0.0%
Utility plant in service	2,030,806	3.4%	1,942,071	3.4%
Construction work in progress	21,355		21,427	
Total utility plant	2,052,161		1,963,498	
Accumulated depreciation	(615,533)		(574,093)	
Utility plant-net	$1,436,628		$1,389,405	

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Accumulated depreciation does not include $204.9 million and $187.4 million at December 31, 2007 and 2006, respectively, which represent accrued asset removal costs reflected on the balance sheets as regulatory liabilities (see Note 1, "Plant and Property and Accrued Asset Removal Costs").

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

	2007		2006	
Thousands, except percentages	Amount	Weighted Average Depreciation Rate	Amount	Weighted Average Depreciation Rate
Non-utility storage	$ 54,083		$ 34,652	
Other	4,881		4,820	
Non-utility plant in service	58,964	2.1%	39,472	2.5%
Construction work in progress	8,185		3,180	
Total non-utility plant	67,149		42,652	
Less accumulated depreciation	(7,904)		(6,916)	
Non-utility plant - net	$ 59,245		$ 35,736	

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

Thousands	2007	2006
Life insurance cash surrender value	$ 46,294	$ 45,234
Note receivable	518	526
Gas pipelines and other	7,258	1,369
Electric generation	-	856
Total other investments	$ 54,070	$ 47,985

Life Insurance Cash Surrender Value. We have invested in key person life insurance contracts to provide an indirect funding vehicle for certain long-term employee benefit plan liabilities.

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

In 2007, we entered into an agreement with TransCanada’s Gas Transmission Northwest (GTN) for the purpose of developing, designing, permitting, constructing and owning a pipeline that would connect GTN’s interstate transmission line to our local gas distribution system to serve markets in Oregon and the western United States (Palomar Pipeline). During 2007, we incurred expenses totaling $6.0 million related to planning and permitting.

Electric Generation. In 2007, Financial Corporation sold its ownership interests in wind power electric generation projects located in California (see Note 2).

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FASB Interpretation No. 46(R), "Consolidation of Variable Interest Entities," provides guidance for determining whether consolidation is required for entities over which control is achieved through means other than voting rights, known as "variable interest entities." We currently do not have any significant interests in variable interest entities for which we are the primary beneficiary.

10 FAIR VALUE OF FINANCIAL INSTRUMENTS:

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

	Dec. 31, 2007		Dec. 31, 2006	
Thousands	Carrying Amount	Estimated Fair Value*	Carrying Amount	Estimated Fair Value
Long-term debt including amount due within one year	$ 517,000	$ 557,916	$ 546,500	$ 595,564

* This estimate is calculated net of commission fees

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

11. USE OF FINANCIAL DERIVATIVES:

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

In the normal course of business, we enter into indexed-price physical forward natural gas commodity purchase (gas supply) contracts to meet the requirements of core utility customers. We also enter into financial derivatives, up to prescribed limits, to hedge price variability related to the physical contracts. Derivatives entered into prudently for future gas years prior to the PGA filing receive SFAS No. 71 regulatory deferral treatment. Derivatives contracts entered into for core utility customer requirements after the annual PGA rate has been set are subject to the PGA incentive sharing mechanism, whereby 67 percent of the changes in fair value are deferred as regulatory assets or liabilities and the remaining 33 percent is recorded to the income statement for contracts not qualifying for hedge accounting and to Other Comprehensive Income for contracts qualifying for hedge accounting. Our interest rate swap qualifies for hedge accounting under SFAS No. 133. During the fourth quarter of 2006, we entered into a number of commodity-based financial derivatives after our PGA filing. The unrealized mark-to-market losses on these hedges subject to sharing were $2.9 million, which was recorded as a loss in 2006 and reversed in 2007.

Certain natural gas purchases from Canadian suppliers are payable in Canadian dollars, including both commodity and demand charges, which expose us to adverse changes in foreign currency rates. Foreign currency forward contracts are used to hedge the fluctuation in foreign currency exchange rates for our commodity and commodity-related demand charges paid in

Canadian dollars. Foreign currency contracts for commodity costs are purchased on a month-to-month basis because the Canadian cost is priced at the average noon-day exchange rate for each month. Foreign currency contracts for demand costs have terms ranging up to 12 months. The gains and losses on the shorter-term currency contracts for commodity costs are recognized immediately in cost of gas. The gains and losses on the currency contracts for demand charges are not recognized in current income but are subject to a regulatory deferral tariff and, as such, are recorded as a derivative asset or liability. These forward contracts qualify for cash flow hedge accounting treatment under SFAS No. 133. The mark-to-market adjustment at December 31, 2007 was an unrealized gain of $0.1 million. This unrealized gain is subject to regulatory deferral and, as such, was recorded as a derivative asset, which is offset by recording a corresponding amount to a regulatory liability account.

In 2007, we entered into a 10-year, $50 million fixed-price forward starting interest rate swap contract to hedge the interest rate exposure related to the forecasted issuance of long-term debt. This interest rate swap is an effective cash flow hedge under SFAS No. 133. We did not use any derivative instruments to hedge interest rates in 2006 or 2005.

The unrealized mark-to-market value at December 31, 2007 for all derivative contracts outstanding was a total loss of $15.4 million consisting of the following unrealized losses: $10.7 million on commodity-based financial swap contracts, $2.1 million on commodity-based financial option contracts, $1.4 million on commodity physical supply contracts and $1.3 million on an interest rate swap contract. These unrealized losses were offset in part by an unrealized gain of $0.1 million on foreign exchange forward contracts.

At December 31, 2007 and 2006, the unrealized gains or losses from mark-to-market valuations of our derivative instruments were primarily reported as regulatory liabilities or regulatory assets because the realized gains or losses at settlement are either included, or are expected to be included, in utility rates pursuant to regulatory deferral mechanisms. The estimated fair values of unrealized gains and losses on derivative instruments outstanding, determined using a discounted cash flow model for swaps and a Black-Scholes model for options, were as follows:

	Fair Value Gains (Losses)			
Thousands	Dec. 31, 2007		Dec. 31, 2006	
	Current	Non-Current	Current	Non-Current
Natural gas commodity-based derivative instruments:				
Natural gas commodity hedge contracts	$(12,099)	$ (2,104)	$(33,528)	$ (9,583)
Interest rate hedge contract	-	(1,330)	-	-
Foreign currency forward purchase contracts	173	-	(135)	-
Total	$(11,926)	$ (3,434)	$(33,663)	$ (9,583)

In 2007 and 2006, we realized net losses of $42.0 million and $20.0 million, respectively, from the settlement of fixed-price financial swap contracts which were recorded as increases to the cost of gas. Net realized gains from the settlement of such contracts in 2005 were $88.9 million and were recorded as decreases to the cost of gas. Realized losses in 2007 were offset by lower gas purchase costs from the underlying hedged floating rate physical supply contracts. The currency exchange rate in all foreign currency forward purchase contracts is included in our cost of gas at settlement; therefore, no gain or loss was recorded from the settlement of those contracts. Any change in value of cash flow hedge contracts that is not included in regulatory recovery is included in other comprehensive income. There were no realized gains or losses on the interest rate swap during 2007.

As of December 31, 2007, all of the natural gas hedges mature by or are extendible to October 31, 2009. The maturity date for our interest rate swap contract is September 30, 2018; however, we expect to cash settle this contract concurrently with the issuance of long-term debt in the second half of 2008.

12. COMMITMENTS AND CONTINGENCIES:

Lease Commitments

We lease land, buildings and equipment under agreements that expire in various years through 2046. Rental expense under operating leases was $4.6 million, $4.4 million and $4.1 million for the years ended December 31, 2007, 2006 and 2005, respectively. The table below reflects the future minimum lease payments due under non-cancelable leases at December 31, 2007. Such payments total $53.0 million for operating leases. The net present value of payments on capital leases less imputed interest was $1.2 million. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities, vehicles and computer equipment.

Thousands	2008	2009	2010	2011	2012	Later years
Operating leases	$ 4,257	$ 4,184	$ 4,177	$ 4,140	$ 4,265	$ 32,003
Capital leases	532	393	255	26	-	-
Minimum lease payments	$ 4,789	$ 4,577	$ 4,432	$ 4,166	$ 4,265	$ 32,003

Gas Purchase and Pipeline Capacity Purchase and Release Commitments

We have signed agreements providing for the reservation of firm pipeline capacity under which we are required to make fixed monthly payments for contracted capacity. The pricing component of the monthly payment is established, subject to change, by U.S. or Canadian regulatory bodies. In addition, we have entered into long-term sale agreements to release firm pipeline capacity. We also enter into gas purchase agreements. The aggregate amounts of these agreements were as follows at December 31, 2007:

Thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2008	$ 302,709	$ 87,453	$ 5,105
2009	118,936	68,631	5,105
2010	53,253	65,344	4,254
2011	24,106	64,989	-
2012	24,106	49,977	-
2013 through 2027	44,193	131,501	-
Total	567,303	467,895	14,464
Less: Amount representing interest	27,538	61,410	567
Total at present value	$ 539,765	$ 406,485	$ 13,897

Our total payments of fixed charges under capacity purchase agreements in 2007, 2006 and 2005 were $90.1 million, $69.2 million and $83.1 million, respectively. Included in the amounts were reductions for capacity release sales of $5.3 million for 2007 and $3.7 million for both 2006 and 2005. In addition, per-unit charges are required to be paid based on the actual quantities shipped under the agreements. In certain take-or-pay purchase commitments, annual deficiencies may be offset by prepayments subject to recovery over a longer term if future purchases exceed the minimum annual requirements.

Environmental Matters

We own, or have previously owned, properties that may require environmental remediation or action. We accrue all material loss contingencies relating to these properties that we believe to be probable of assertion and reasonably estimable. We continue to study the extent of our potential environmental liabilities, but due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several environmental site investigations, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot be reasonably estimated. We regularly review our remediation liability for each site where we may be exposed to remediation responsibilities. The costs of environmental remediation are difficult to estimate. A number of steps are involved in each environmental remediation effort, including site investigations, remediation, operations and maintenance, monitoring and site closure. Each of these steps may, over time, involve a number of alternative actions, each of which can change the course of the effort. In certain cases, in addition to us, there are a number of other potentially responsible parties, each of which, in proceedings and negotiations with other potentially responsible parties and regulators, may influence the course of the remediation effort. The allocation of liabilities among the potentially responsible parties is often subject to dispute and can be highly uncertain. The events giving rise to environmental liabilities often occurred many decades ago, which complicates the determination of allocating liabilities among potentially responsible parties. Site investigations and remediation efforts often develop slowly over many years. In addition, disputes may arise between potentially responsible parties and regulators as to the severity of particular environmental matters and what remediation efforts are appropriate. These disputes could lead to adversarial administrative proceedings or litigation, with uncertain outcomes.

To the extent reasonably estimable, we estimate the costs of environmental liabilities using current technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of probable cost, we record the liability at the lower end of this range. It is likely that changes in these estimates will occur throughout the remediation process for each of these sites due to uncertainty concerning our responsibility, the complexity of environmental laws and regulations and the selection of compliance alternatives. The status of each of the sites currently under investigation is provided below.

Gasco site. We own property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (the Gasco site). The Gasco site has been under investigation by us for environmental contamination under the Oregon Department of Environmental Quality's (ODEQ) Voluntary Clean-Up Program. In June 2003, we filed a Feasibility Scoping Plan and an Ecological and Human Health Risk Assessment with the ODEQ, which outlined a range of remedial alternatives for the most contaminated portion of the Gasco site. In May 2007, we completed a revised upland remediation investigation report and submitted it to the ODEQ for review. During 2007, we accrued an additional $19.3 million for estimated liabilities based on updated information for the development of proposed studies of in-water source control and completion of remedial actions. We have a net liability of $21.2 million at December 31, 2007 for the Gasco site, which is estimated at the low end of the range of potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot be estimated.

Siltronic site. We previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (the Siltronic site). We are currently working with the ODEQ to develop a study of manufactured gas plant wastes on the uplands at this site. During 2007, the estimated liability for this site increased by $1.8 million related to future expenditures in connection with the study, which is at the low end of the range of potential additional liability because no amount within the range is considered to be more likely than another and the high end of the range cannot be estimated. The net liability at December 31, 2007 for the Siltronic site is $1.5 million.

Portland Harbor site. In 1998, the ODEQ and the U.S. Environmental Protection Agency (EPA) completed a study of sediments in a 5.5-mile segment of the Willamette River (Portland Harbor) that includes the area adjacent to the Gasco site and the Siltronic site. The Portland Harbor was listed by the EPA as a Superfund site in 2000 and we were notified that we are a potentially responsible party. We then joined with other potentially responsible parties, referred to as the Lower Willamette Group, to fund environmental studies in the Portland Harbor. Subsequently, the EPA approved a Programmatic Work Plan, Field Sampling Plan and Quality Assurance Project Plan for the Portland Harbor Remedial Investigation/Feasibility Study (RI/FS), completion of which is currently expected in 2009. The EPA and the Lower Willamette Group are conducting focused studies on approximately nine miles of the lower Willamette River, including the segment previously studied by the EPA. During 2007, we received a revised estimate and following a review of that estimate, we accrued an additional $13.6 million for additional expenditures related to RI/FS development and environmental remediation and monitoring after the RI/FS work plan is completed. As of December 31, 2007, we have a net liability of $13.8 million, which is at the low end of the range of the potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot be estimated.

In April 2004, we entered into an Administrative Order on Consent providing for early action removal of a deposit of tar in the river sediments adjacent to the Gasco site. We completed the removal of the tar deposit in the Portland Harbor in October 2005 and on November 5, 2005, the EPA approved the completed project. The total cost of removal, including technical work, oversight, consultant fees, and legal fees and ongoing monitoring, was about $10.4 million. In 2007 we accrued $0.5 million for additional monitoring and reporting expense. To date, we have paid $9.8 million on work related to the removal of the tar deposit. As of December 31, 2007, we have a net liability of $1.0 million, which is at the low end of the range of the potential liability because no amount within the range is considered to be more likely than another and the high end of the range cannot be estimated.

Central Service Center site. In 2006, we received notice from the ODEQ that our Central Service Center in southeast Portland (the Central Service Center site) was assigned a high priority for further environmental investigation. Previously there were three manufactured gas storage tanks on the premises. The ODEQ believes there could be site contamination associated with releases of condensate from stored manufactured gas as a result of historic gas handling

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practices. In the early 1990s, we excavated waste piles and much of the contaminated surface soils and removed accessible waste from some of the abandoned piping. In early 2007, we received notice that this site has been added to the ODEQ's list of sites where releases of hazardous substances have been confirmed and its list where additional investigation or cleanup is necessary. During 2007, we accrued $0.5 million for estimated liabilities related to the design of an investigational plan for this site in cooperation with the ODEQ. We cannot estimate a range of liability until studies are completed.

Front Street site. The Front Street site was the former location of a gas manufacturing plant operated by our predecessor. Although it is outside the geographic scope of the current Portland Harbor site sediment studies, the EPA directed the Lower Willamette Group to collect a series of surface and subsurface sediment samples off the river bank where that facility was located. Based on the results of that sampling, the EPA notified the Lower Willamette Group that additional sampling would be required. Until the results of that sampling are evaluated, a future cost cannot be reasonably estimated.

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

Accrued Liabilities relating to Environmental sites. Until the current year, we had not been able to determine the timing of our environmental liabilities and therefore had classified no liabilities as current prior to June 2007. The following table summarizes the accrued liabilities relating to environmental sites at December 31, 2007 and 2006:

	Current Liabilities		Non-Current Liabilities	
Thousands	2007	2006	2007	2006
Gasco site	$ 6,901	$ -	$ 14,342	$ 6,414
Siltronic site	-	-	1,540	43
Portland Harbor site	-	-	14,821	2,149
Central Service Center site	-	-	529	-
Other sites	-	-	167	62
Total	$ 6,901	$ -	$ 31,399	$ 8,668

Regulatory and Insurance Recovery for Environmental Matters. In May 2003, the OPUC approved our request for deferral of environmental costs associated with specific sites, including the Gasco, Siltronic, Portland Harbor and Front Street sites. The authorization, which was extended through January 2008 and expanded to include the Oregon Steel Mills site, allows us to defer and seek recovery of unreimbursed environmental costs in a future general rate case. Beginning in 2006, the OPUC authorized us to accrue interest on deferred 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. An application for further extension of the regulatory approval to defer environmental costs and accrued interest is pending. As of December 31, 2007, we have paid a cumulative total of $24.8 million relating to the named sites since the effective date of the deferral authorization.

On a cumulative basis, we have recognized a total of $67.8 million for environmental costs, including legal, investigation, and monitoring and remediation costs. Of this total, $29.5 million has been spent to-date and $38.3 million is reported as an outstanding liability. At December 31, 2007, we had a regulatory asset of $63.1 million which includes $24.8 million of total paid expenditures to date, $35.1 million for additional environmental accruals for costs expected to be paid in the future and accrued interest of $3.2 million. We believe the recovery of these costs is probable through the regulatory process. We intend to pursue recovery of these environmental costs from our general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. We consider insurance recovery of some portion of our environmental costs probable based on a combination of factors, including a review of the terms of our insurance policies, the financial condition of the insurance companies providing coverage, a review of successful claims filed by other utilities with similar gas manufacturing facilities, and Oregon legislation that allows an insured party to seek recovery of "all sums" from one insurance company. We have initiated settlement discussions with a majority of our insurers but continue to anticipate that our overall insurance recovery effort will extend over several years.

We anticipate that our regulatory recovery of environmental cost deferrals will not be initiated within the next 12 months because we will not have completed our insurance recovery efforts during that time period. As such we have classified our regulatory assets for environmental cost deferrals as non-current. The following table summarizes the regulatory assets and accrued liabilities relating to environmental matters at December 31, 2007 and 2006:

	Non-Current Regulatory Assets	
Thousands	2007	2006
Gasco site	$ 29,042	$ 10,336
Siltronic site	2,227	477
Portland Harbor site	30,869	16,769
Central Service Center site	545	-
Other sites	371	291
Total	$ 63,054	$ 27,873

Legal Proceedings

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

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

NORTHWEST NATURAL GAS COMPANY
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

Thousands, except per share amounts	Quarter ended March 31	June 30	Sept. 30	Dec. 31	Total
2007					
Operating revenues	$ 394,091	$ 183,249	$ 124,245	$ 331,608	$ 1,033,193
Net operating revenues	139,008	64,118	49,663	116,253	369,042
Net income (loss)	48,075	2,617	(5,908)	29,713	74,497
Basic earnings (loss) per share	1.77	0.10	(0.22)	1.12	2.78*
Diluted earnings (loss) per share	1.76	0.10	(0.22)	1.11	2.76*
2006					
Operating revenues	$ 390,391	$ 170,979	$ 114,914	$ 336,888	$ 1,013,172
Net operating revenues	125,464	61,747	41,341	111,624	340,176
Net income (loss)	41,033	1,994	(9,724)	30,112	63,415
Basic earnings (loss) per share	1.49	0.07	(0.35)	1.10	2.30*
Diluted earnings (loss) per share	1.48	0.07	(0.35)	1.09	2.29*

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

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

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
	Balance at beginning of period	Additions		Deductions	Balance at end of period
		Charged to costs and expenses	Charged to other accounts	Net Write-offs	
Thousands (year ended Dec. 31)					
2007					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 3,033	$ 2,978	$ 0	$ 3,121	$ 2,890
2006					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 3,067	$ 3,036	$ 0	$ 3,070	$ 3,033
2005					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$ 2,434	$ 3,034	$ 0	$ 2,401	$ 3,067

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

As of December 31, 2007, the principal executive officer and principal financial officer of Northwest Natural Gas Company (NW Natural) have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended). Based upon that evaluation, the principal executive officer and principal financial officer of NW Natural have concluded that such disclosure controls and procedures are effective to ensure that information required to be disclosed by us and included in our reports filed with the Securities and Exchange Commission (Commission) under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the Commission's rules and forms and are also effective to ensure that information required to be disclosed by us and included in our reports filed with or furnished to the Commission under the Exchange Act is accumulated and communicated to our management as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

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

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

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

ITEM 9B. OTHER INFORMATION

(a) Entry into a Material Service Agreement

On February 8, 2008, we entered into a service agreement with Northwest Pipeline GP, for an additional 120,000 therms per day of firm transportation capacity form the U.S. Rocky Mountain region upon assignment of the capacity from March Point Cogeneration Company. The primary term of the transportation service agreement will begin on January 1, 2017 and end on December 31, 2046.

This contract is included as Exhibit 10j.(9).

(b) Entry into Service Agreement Amendment

On February 12, 2008, we entered into a service agreement amendment with Northwest Pipeline GP to extend the primary term of the previous agreement, dated June 29, 1990, to September 30, 2044. The amendment also provides an additional 351,550 therms per day of firm transportation capacity from the U.S. Rocky Mountain region.

This contract is included as Exhibit 10j.(7).

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information concerning our Board of Directors, its Committees and the Audit Committee financial expert contained in NW Natural's definitive Proxy Statement for the May 22, 2008 Annual Meeting of Shareholders is hereby incorporated by reference. The information concerning "Section 16(a) Beneficial Ownership Reporting Compliance" and "Corporate Governance" contained in our definitive Proxy Statement for the May 22, 2008 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2007	Positions held during last five years
Mark S. Dodson	62	Chief Executive Officer (2007-); President and Chief Executive Officer (2003-2007).
Gregg S. Kantor	50	President and Chief Operating Officer (2007 -); Executive Vice President (2006 -2007); Senior Vice President, Public and Regulatory Affairs (2003-2006).
David H. Anderson	46	Senior Vice President and Chief Financial Officer (2004-); Senior Vice President and Chief Financial Officer, TXU Gas Company (2004); Senior Vice President, Principal Accounting Officer and Controller (2003-2004); Vice President of Investor Relations and Shareholder Services, TXU Corp. (1997-2003).
Margaret D. Kirkpatrick	53	Vice President and General Counsel (2005-); Partner, Stoel Rives LLP (1991- 2005).
Lea Anne Doolittle	52	Vice President, Human Resources (2000-).
J. Keith White	54	Vice President, Business Development and Energy Supply (2007-); Managing Director, Gas Operations and Wholesale Services (2005-2006); Managing Director and Chief Strategic Officer (2003-2005); Director, Strategic Development (2003); Director, Corporate and Business Development (2001-2003).
David R. Williams	54	Vice President, Utility Services (2007-); Director, Acquire Customers (2006); Director, Gas Operations (2005-2006); General Manager, Utility Operations (1999-2004)
Grant M. Yoshihara	52	Vice President, Utility Operations (2007-); Managing Director, Utility Services (2005-2006); General Manager, Consumer Services (2003-2004).
Stephen P. Feltz	52	Treasurer and Controller (1999-).
C. J. Rue	62	Secretary (1982-2007); Assistant Treasurer (1987-2007).
Richelle T. Luther	39	Assistant Secretary (2002-).

Each executive officer serves successive annual terms; present terms end on May 22, 2008. There are no family relationships among our executive officers.

NW Natural has adopted a Code of Ethics for all employees, including our chief executive officer, chief financial officer and principal accounting officer, and a Financial Code of Ethics that

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applies to senior financial employees, both of which are available on our website at www.nwnatural.com.

ITEM 11. EXECUTIVE COMPENSATION

The information concerning "Executive Compensation" and "Report of the Organization and Executive Compensation Committee on Executive Management Compensation" contained in our definitive Proxy Statement for the May 22, 2008 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2007 is reflected in Part III, Item 10, above.

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

The following table sets forth information regarding compensation plans under which equity securities of NW Natural are authorized for issuance as of December 31, 2007 (see Note 4 to the Consolidated Financial Statements):

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
Long-Term Incentive Plan (LTIP) (Target Award)[1]	87,998	n/a	299,721
Restated Stock Option Plan	357,750	$ 35.36	1,035,400
Employee Stock Purchase Plan	23,213	$ 40.95	199,820
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)[2]	6,967	n/a	n/a
Directors Deferred Compensation Plan (DDCP)[2]	74,580	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)[3]	27,024	n/a	n/a
Non-Employee Directors Stock Compensation Plan[4]	n/a	n/a	n/a
Total	577,532		1,534,941

The information captioned "Beneficial Ownership of Common Stock by Directors and Executive Officers" contained in our definitive Proxy Statement for the May 22, 2008 Annual Meeting of Shareholders is incorporated herein by reference.

1 Shares issued pursuant to the LTIP do not include an exercise price, but are payable by us when the award criteria are satisfied. If the maximum awards were paid pursuant to the performance-based awards outstanding at December 31, 2007, the number of shares shown in column (a) would increase by 81,665 shares and the number of shares shown in column (c) would decrease by 81,665 shares.

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

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

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

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

The information captioned "Transactions with Related Persons" and "Corporate Governance" in the Company’s definitive Proxy Statement for the May 22, 2008 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned "2007 and 2006 Audit Firm Fees" in the Company’s definitive Proxy Statement for the May 22, 2008 Annual Meeting of Shareholders is hereby incorporated by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

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

2. List of Exhibits filed:

Reference is made to the Exhibit Index commencing on page 115.

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SIGNATURES

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

NORTHWEST NATURAL GAS COMPANY

Date: February 29, 2008

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

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

SIGNATURE	TITLE	DATE
/s/ Mark S. Dodson Mark S. Dodson, Chief Executive Officer	Principal Executive Officer and Director	February 29, 2008
/s/ David H. Anderson David H. Anderson Senior Vice President and Chief Financial Officer	Principal Financial Officer	February 29, 2008
/s/ Stephen P. Feltz Stephen P. Feltz Treasurer and Controller	Principal Accounting Officer	February 29, 2008
/s/ Timothy P. Boyle Timothy P. Boyle	Director	)
/s/ Martha L. Byorum Martha L. Byorum	Director	)
/s/ John D. Carter John D. Carter	Director	)
/s/ C. Scott Gibson C. Scott Gibson	Director	)
/s/ Tod R. Hamachek Tod R. Hamachek	Director	)
/s/ Randall C. Papé Randall C. Papé	Director	) February 29, 2008
/s/ Jane L. Peverett Jane L. Peverett	Director	)
/s/ George J. Puentes George J. Puentes	Director	)
/s/ Richard G. Reiten Richard G. Reiten	Director	)
/s/ Kenneth Thrasher Kenneth Thrasher	Director	)
/s/ Russell F. Tromley Russell F. Tromley	Director	)

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EXHIBIT INDEX
To
Annual Report on Form 10-K
For Fiscal Year Ended
December 31, 2007

Exhibit Number	Document
*3a.	Restated Articles of Incorporation, as filed and effective May 31, 2006 and amended May 31, 2006 (incorporated herein by reference to Exhibit 3a. to Form 10-K for 2006, File No. 1-15973).
*3b.	Bylaws as amended May 24, 2007 (incorporated herein by reference to Exhibit 3.1 to Form 8-K dated May 29, 2007, File No. 1-15973).
*4a.	Copy of Mortgage and Deed of Trust, dated as of July 1, 1946, to Bankers Trust and R. G. Page (to whom Stanley Burg is now successor), Trustees (incorporated herein by reference to Exhibit 7(j) in File No. 2-6494); and copies of Supplemental Indentures Nos. 1 through 14 to the Mortgage and Deed of Trust, dated respectively, as of June 1, 1949, March 1, 1954, April 1, 1956, February 1, 1959, July 1, 1961, January 1, 1964, March 1, 1966, December 1, 1969, April 1, 1971, January 1, 1975, December 1, 1975, July 1, 1981, June 1, 1985 and November 1, 1985 (incorporated herein by reference to Exhibit 4(d) in File No. 33-1929); Supplemental Indenture No. 15 to the Mortgage and Deed of Trust, dated as of July 1, 1986 (filed as Exhibit 4(c) in File No. 33-24168); Supplemental Indentures Nos. 16, 17 and 18 to the Mortgage and Deed of Trust, dated, respectively, as of November 1, 1988, October 1, 1989 and July 1, 1990 (incorporated herein by reference to Exhibit 4(c) in File No. 33-40482); Supplemental Indenture No. 19 to the Mortgage and Deed of Trust, dated as of June 1, 1991 (incorporated herein by reference to Exhibit 4(c) in File No. 33-64014); and Supplemental Indenture No. 20 to the Mortgage and Deed of Trust, dated as of June 1, 1993 (incorporated herein by reference to Exhibit 4(c) in File No. 33-53795).
*4d.	Copy of Indenture, dated as of June 1, 1991, between the Company and Bankers Trust Company, Trustee, relating to the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4(e) in File No. 33-64014).
*4e.	Officers' Certificate dated June 12, 1991 creating Series A of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4e. to Form 10-K for 1993, File No. 0-994).
*4f.	Officers' Certificate dated June 18, 1993 creating Series B of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4f. to Form 10-K for 1993, File No. 0-994).
*4f.(1)	Officers' Certificate dated January 17, 2003 relating to Series B of the Company's Unsecured Medium-Term Notes and supplementing the Officers' Certificate dated June 18, 1993 (incorporated herein by reference to Exhibit 4f.(1) to Form 10-K for 2002, File No. 0-994).

*4i.	Form of Credit Agreement between Northwest Natural Gas Company and each of JPMorgan Chase Bank, N.A., and Bank of America, N.A., dated as of May 31, 2007, including Form of Note (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated June 1, 2007, File No. 1-15973).
*4j.	Distribution Agreement, dated September 28, 2004 as amended and restated on December 7, 2006, among the Company, Merrill Lynch, Pierce Fenner & Smith Incorporated, UBS Securities LLC, J.P. Morgan Securities Inc. and Piper Jaffray & Co (incorporated herein by reference to Exhibit 4j. to Form 10-K for 2006, File No. 1-15973).
*4k.	Form of Secured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated October 4, 2004, File No. 1-15973).
*4l.	Form of Unsecured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.2 to Form 8-K dated October 4, 2004, File No. 1-15973).
*10j.	Transportation Agreement, dated June 29, 1990, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j. to Form 10-K for 1993, File No. 0-994).
*10j.(1)	Replacement Firm Transportation Agreement, dated July 31, 1991, between the Company and Northwest Pipeline GP (incorporated herein by reference to Exhibit 10j.(2) to Form 10-K for 1992, File No. 0-994).
*10j.(2)	Firm Transportation Service Agreement, dated November 10, 1993, between the Company and Pacific Gas Transmission Company (incorporated herein by reference to Exhibit 10j.(2) to Form 10-K for 1993, File No. 0-994).
*10j.(3)	Service Agreement, dated June 17, 1993, between Northwest Pipeline GP and the Company (incorporated herein by reference to Exhibit 10j.(3) to Form 10-K for 1994, File No. 0-994).
*10j.(5)	Firm Transportation Service Agreement, dated June 22, 1994, between Pacific Gas Transmission Company and the Company (incorporated herein by reference to Exhibit 10j.(5) to Form 10-K for 1995, File No. 0-994).
*10j.(6)	Firm Service Agreement between the Company and Westcoast Energy Inc., dated as of April 1, 2003 (incorporated herein by reference to Exhibit 10 to Form 10-Q for quarter ended March 31, 2003, File No. 0-994).
10j.(7)	Service Agreement Amendment, dated February 12, 2008, between the Company and Northwest Pipeline GP.
10j.(8)	Service Agreement, dated February 8, 2008, between the Company and Northwest Pipeline GP.
10j.(9)	Agreement between the Company and March Point Cogeneration Company, dated February 8, 2008.
12	Statement re computation of ratios of earnings to fixed charges.

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

Executive Compensation Plans and Arrangements:

10b.	Executive Supplemental Retirement Income Plan (2007 Restatement).
10b.(1)	Supplemental Executive Retirement Plan, effective September 1, 2004 restated December 20, 2007.
*10b.(2)	Northwest Natural Gas Company Supplemental Trust, effective January 1, 2005, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.7 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10b.(3)	Northwest Natural Gas Company Umbrella Trust for Directors, effective January 1, 1991, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.5 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10b.(4)	Northwest Natural Gas Company Umbrella Trust for Executives, effective January 1, 1988, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.6 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10c.	Restated Stock Option Plan, as amended effective December 14, 2006 (incorporated herein by reference to Exhibit 10c. to From 10-K for 2006, File No. 1-15973).
*10c.(1)	Form of Restated Stock Option Plan Agreement (incorporated herein by reference to Exhibit 10.3 to Form 10-Q dated November 3, 2005, File No. 1-15973).
10e.	Executive Deferred Compensation Plan, effective as of January 1, 1987, restated as of February 28, 2008.
10f.	Directors Deferred Compensation Plan, effective June 1, 1981, restated as of February 28, 2008.
10f.(1)	Deferred Compensation Plan for Directors and Executives effective January 1, 2005, restated February 28, 2008.
*10g.	Form of Indemnity Agreement as entered into between the Company and each director and executive officer (incorporated herein by reference to Exhibit 10g. to Form 10-K for 1988, File No. 0-994).
*10i.	Non-Employee Directors Stock Compensation Plan, as amended effective December 15, 2005 (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated December 16, 2005, File No. 1-15973).

*10k.	Executive Annual Incentive Plan, effective January 1, 2003 (incorporated herein by reference to Exhibit 10 k. to Form 10-K for 2002, File No. 0-994)
*10o.	Form of amended and restated executive change in control severance agreement between the Company and each executive officer other than Mark S. Dodson (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated December 19, 2006, File No. 1-15973).
*10o.-1	Amended and restated executive change in control severance agreement dated December 14, 2006 between the Company and Mark S. Dodson (incorporated herein by reference to Exhibit 10.3 to Form 8-K dated December 19, 2006, File No. 1-15973).
*10p.	Employment Agreement dated July 2, 1997, between the Company and an executive officer (incorporated herein by reference to Exhibit 10(a) for Form 10-Q for the quarter ended September 30, 1997, File No. 0-994).
*10p.-1	Amendment dated December 18, 1997 to employment agreement dated July 2, 1997, between the Company and an executive officer (incorporated herein by reference to Exhibit 10p.-1 to Form 10-K for 1997, File No. 0-994).
*10p.-2	Amendment dated September 24, 1998 to employment agreement dated July 2, 1997, as previously amended, between the Company and an executive officer (incorporated herein by reference to Exhibit 10(g) to Form 10-Q for the quarter ended September 30, 1998, File No. 0-994).
*10p.-3	Employment Agreement dated December 20, 2002, between the Company and an executive officer (incorporated herein by reference to Exhibit 10p.-3 to Form 10-K for 2002, File No. 0-994).
*10p.-4	Amendment dated December 14, 2006 to employment agreement dated December 20, 2002 between the Company and Mark S. Dodson (incorporated herein by reference to Exhibit 10.8 to Form 8-K dated December 19, 2006, File No. 1-15973).
*10v.	Northwest Natural Gas Company Long-Term Incentive Plan, as amended and restated effective July 26, 2001 (incorporated herein by reference to Exhibit 10(c) to Form 10-Q for the quarter ended June 30, 2001, File No. 0-994).
*10w.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.8 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10w.(1)	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated February 21, 2007, File No. 1-15973).
10w.(2)	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan.

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*10x.	Form of Restricted Stock Bonus Agreement under the Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.9 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10x.(1)	Restricted Stock Bonus Agreement with an executive officer dated July 26, 2006 (incorporated by reference to Exhibit 10.1 to Form 8-K dated July 28, 2006, File No. 1-15973).
*10z.(1)	Summary of non-employee director compensation, effective January 1, 2007 (incorporated herein by reference to Form 8-K dated October 3, 2006, File No. 1-15973).
*10aa.	Form of Consent dated December 14, 2006 entered into by each executive officer (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 19, 2006, File No. 1-15973).
10bb.	Consent to Amendment of Deferred Compensation Plan for Directors and Executives, dated February 28, 2008 entered into by each executive officer.

* Incorporated herein by reference as indicated

Section 2: EX-10.J(7) (SERVICE AGREEMENT AMENDMENT , DATED FEBRUARY 12, 2008)

Exhibit 10j.(7)

Rate Schedule TF-1 Service Agreement Amendment

Contract No. 100058

Amendment No. 6

THIS AMENDMENT is made and entered into on February 12, 2008, by and between Northwest Pipeline GP (Transporter) and Northwest Natural Gas Company (Shipper).

WHEREAS :

A Transporter and Shipper are parties to that certain Rate Schedule (TF-1) Service Agreement dated June 29,1990 and assigned Contract No. 100058 (Agreement).

B Transporter and Shipper desire to amend the Agreement to extend the Primary Term End Date associated with 34,000 Dth/d of Contract Demand along with the associated MDQs at the Collins Gulch (2200 Dths) Green River Gathering (3187 Dths), Ignacio Plant (7938 Dths), Opal Plant (7925 Dths), Shute Creek Plant (6875 Dths) and Westgas Arkansas (5875 Dths) receipt points and MDDOs at the Albany (5000 Dths), Battle Ground (100 Dths), Gresham (11000 Dths), Jefferson/Scio (200 Dths), Kelso/Beaver (3000 Dths), Marion (100 Dths), Molalla (1000 Dths), Monitor (600 Dths), Mount Angel (1000 Dths), North Eugene (2500 Dths), Oregon City (2000 Dths) and South Eugene (7500 Dths) delivery points from September 30, 2009 to September 30, 2044. This contract term extension is being made pursuant to Shipper's Right of First Refusal decision to match the highest competing bid for capacity posted for competitive bid on January 22, 2008 in the All Shipper's Notices # 08-022 and # 08-023.

C Transporter and Shipper desire to further amend the Agreement to add a non-confirming provision that reflects the current Primary Term End Date associated with the capacity that is not required to be extended and the new Primary Term End Date associated with the capacity Shipper matched by exercising its Right of First Refusal.

THEREFORE, in consideration of the premises and mutual covenants set fourth herein, Transporter and Shipper agree as follows :

1. As of the effective date set forth thereon, the Exhibit A attached hereto supercedes and replaces the previously effective Exhibit A to the Agreement.

2. The additional exhibits noted on the attached Exhibit A as applicable to the Agreement, if any, also are attached hereto and, as of the effective dates set forth thereon, supercede and replace any previously effective corresponding exhibits to the Agreement.

IN WITNESS WHEREOF Transporter and Shipper have executed this Amendment as of the date first set forth above.

Northwest Natural Gas Company	Northwest Pipeline GP
By : /S/	By : /S/
Name: RANDOLPH S. FRIEDMAN	Name: JANE F HARRISON
Title : DIRECTOR, GAS SUPPLY	Title : MANAGER NWP MARKETING SERVICES

EXHIBIT A
(Dated February 12, 2008, Effective February 12, 2008)
to the
Rate Scheduled TF-1 Service Agreement
(Contract No. 100058)
between Northwest Pipeline GP
and Northwest Natural Gas Company

SERVICE DETAILS

1. Transportation Contract Demand (CD): 35,155 Dth per Day

2. Primary Receipt Point (s):

Point ID Name	Maximum Daily Quantities (Dth)
4 IGNACIO PLANT	7938
80 GREEN RIVER GATHERING	3187
297 SUMAS RECEIPT	589
541 SHUTE CREEK PLANT RECEIPT	6875
543 OPAL PLANT	8491
552 WESTGAS ARKANSAS	5875
700 COLLINS GULCH	2200
Total	35155

3. Primary Delivery Point (s):

Point ID Name	Maximum Daily Delivery Obligation (Dth)	Delivery Pressure (psig)
219 BATTLE GROUND	1255	150
229 KELSO/BEAVER	3000	450
304 GRESHAM	11000	150
309 OREGON CITY	2000	165
312 MOLALLA	1000	400
313 MONITOR	600	150
314 MOUNT ANGEL	1000	150
322 MARION	100	150
324 JEFFERSON/SCIO	200	400
327 ALBANY	5000	400
334 NORTH EUGENE	2500	400
336 SOUTH EUGENE	7500	400
Total	35155	

4. Customer Category:

a. Large Customer

b. Incremental Expansion Customer: No

5. Recourse or Discounted Recourse Transportation Rates:

a. Reservation Charge (per Dth of CD):

Maximum Base Tariff Rate, plus applicable surcharges

b. Volumetric Charge (per Dth):

Maximum Base Tariff Rate, plus applicable surcharges

c. Additional Facility Reservation Surcharge Pursuant to Section 3:4 of Rate

Schedule TF-1 (per Dth of CD): None

d. Rate Discount Conditions Consistent with Section 3.5 of Rate Schedule TF-1:

Not Applicable

6. Transportation Term:

a. Primary Term Begin Date:

April 01, 1993

b. Primary Term End Date:

September 30, 2044

c. Evergreen Provision:

Yes, standard bi-lateral evergreen under Section 12.2 of Rate Schedule TF-1

7. Contract Specific OFO Parameters: None.

8. Regulatory Authorization: 18 CFR 284.223

9. Additional Exhibits:

Exhibit B Yes, dated February 12, 2008

Exhibit C Yes, dated February 12, 2008

Exhibit D No

EXHIBIT B
(Dated February 12, 2008, Effective February 12, 2008)
to the
Rate Schedule TF-1 Service Agreement
(Contract No. 100058)
between Northwest Pipeline GP
and Northwest Natural Gas Company

NON-CONFORMING PROVISIONS

1. Transportation Term - Primary Term End Date

The primary term will extend through September 30, 2013 for 35,155 Dths/day of contract demand.

The primary term will extend through September 30, 2044 for 34,000 Dths/day of contract demand from the Collins Gulch (2200 Dths), Green River Gathering (3187 Dths), Ignacio Plant (7938 Dths), Opal Plant (7925 Dths), Shute Creek Plant (6875 Dths) and Westgas Arkansas (5875 Dths) receipt points and the Albany (5000 Dths), Battle Ground (100 Dths), Gresham (11000 Dths), Jefferson/Scio (200 Dths), Kelso/Beaver (3000 Dths), Marion (100 Dths), Molalla (1000 Dths), Monitor (600 Dths), Mount Angel (1000 Dths), North Eugene (2500 Dths), Oregon City (2000 Dths) and South Eugene (7500 Dths) delivery points.

EXHIBIT C
(Dated February 12, 2008, Effective February 14, 2007)
to the
Rate Schedule TF-1 Service Agreement
(Contract No. 100058)
between Northwest Pipeline GP
and Northwest Natural Gas Company

FACILITY REIMBURSEMENT OBLIGATION

1. DESCRIPTION OF NEW FACILITIES:

The new facilities contemplated by Section 1(b) of Rate Schedule TF-1, which are necessary to provide service under this agreement include the following:

Upgrades to the Battle Ground Meter Station in Clark County, Washington to provide up to 1,713 Dth per day of delivery capacity at 150 psig.

2. RESPONSIBILITY FOR NEW FACILITY COSTS:

The total estimated reimbursable cost of facilities is $11,700 with an estimated annual cost of service of $3,412. Pursuant to Section 21 of the General Terms and Conditions of Transporter's FERC Gas Tariff, Shipper is responsible to pay for the actual cost of service for the new facilities described above and has elected the payment option set forth below.

3. TERMS AND CONDITIONS OF FACILITY REIMBURSEMENT CHARGE:

a. Type of Charge: Monthly Cost of Service charge.

b. Charge: $235.

The monthly cost of service charge is calculated using the methodologies underlying Transporter's currently effective transportation rates. Except for depreciable life purpose, the term used for calculating the cost of service is stated in item 3c.

c. Term of Charge:

13.6 years: Reflects the remaining applicable primary contract term.

RANDOLPH S. FRIEDMAN	JANE F HARRISON
(Shipper)	Northwest Pipeline GP

Section 3: EX-10.J(8) (SERVICE AGREEMENT, DATED FEBRUARY 12, 2008)

Exhibit 10j.(8)

Rate Schedule TF-1 Service Agreement

Contract No. 136455

THIS SERVICE AGREEMENT (Agreement) is made and entered into on February 08, 2008, by and between Northwest Pipeline GP (Transporter) and Northwest Natural Gas Company (Shipper).

WHEREAS:

A. Pursuant to the procedure set forth in Section 22 of the General Terms and Conditions of Transporter's FERC Gas Tariff, Shipper acquired certain transportation capacity that was permanently released by **March Point Cogeneration Company** from contract **100055**.

THEREFORE, in consideration of the premises and mutual covenants set forth herein, Transporter and Shipper agree as follows:

1. Tariff Incorporation. Rate Schedule TF-1 and the General Terms and Conditions (GT&C) that apply to Rate Schedule TF-1, as such may be revised from time to time in Transporter's FERC Gas Tariff (Tariff), are incorporated by reference as part of this Agreement, except to the extent that any provisions thereof may be modified by non-conforming provisions herein.

2. Transportation Service. Subject to the terms and conditions that apply to service under this Agreement, Transporter agrees to receive, transport and deliver natural gas for Shipper, on a firm basis. The Transportation Contract Demand, the Maximum Daily Quantity at each Primary Receipt Point, and the Maximum Daily Delivery Obligation at each Primary Delivery Point are set forth on Exhibit A. If contract specific OFO parameters are set forth on Exhibit A, whenever Transporter requests during the specified time period, Shipper agrees to flow gas as requested by Transporter, up to the specified volume through the specified transportation corridor.

3. Transportation Rates. Shipper agrees to pay Transporter for all services rendered under this Agreement at the rates set forth or referenced herein. Reservation charges apply to the Contract Demand set forth on Exhibit A. The maximum currently effective rates (Recourse Rates) set forth in the Statement of Rates in the Tariff, as revised from time to time, that apply to the Rate Schedule TF-1 customer category identified on Exhibit A, will apply to service hereunder unless and to the extent that discounted Recourse Rates or awarded capacity release rates apply as set forth on Exhibit A or

negotiated rates apply as set forth on Exhibit D. Addiotionally, if applicable under Section 21 of the GT&C, Shipper agrees to pay Transporter a facility reimbursement charge as set forth on Exhibit C.

4. Transportation Term. This Agreement becomes effective on the date first set forth above. The primary term begin date for the transportation service hereunder is set forth on Exhibit A. This Agreement will remain in full force and effect through the primary term end date set forth on Exhibit A and, if Exhibit A indicates that an evergreen provision applies, through the established evergreen rollover periods thereafter until terminated in accordance with the notice requirements under the applicable evergreen provision.

5. Non-Conforming Provisions. All aspects in which this Agreement deviates from the Tariff, if any, are set forth as non-conforming provisions on Exhibit B. If Exhibit B includes any material non-conforming provisions, Transporter will file the Agreement with the Federal Energy Regulatory Commission (Commission) and the effectiveness of such non-conforming provisions will be subject to the Commission acceptance of Transporter's filing of the non-conforming Agreement.

6. Capacity Release. If Shipper is a temporary capacity release Replacement Shipper, any capacity release conditions, including recall rights, are set forth on Exhibit A.

7. Exhibit Incorporation. Exhibit A is attached hereto and incorporated as part of this Agreement. If Exhibits B, C and/or D apply, as noted on Exhibit A to this Agreement, then such Exhibits also are attached hereto and incorporated as part of this Agreement.

8. Regulatory Authorization. Transportation service under this Agreement is authorized pursuant to the Commission regulations set forth on Exhibit A.

9. Superseded Agreements. When this Agreement takes effect, it supersedes, cancels and terminates the following agreement(s): Original Firm Agreement 100055 dated 4/1/1993.

IN WITNESS WHEREOF, Transporter and Shipper have executed this Agreement on February 08, 2008.

Northwest Natural Gas Company

By: /s/

Name: RANDOLPH S. FRIEDMAN

Title: DIRECTOR, GAS SUPPLY

Northwest Pipeline GP

By: /s/

Name: JANE F. HARRISON

Title: MANAGER NWP MARKETING SERVICES

EXHIBIT A
(Dated February 08, 2008, Effective February 08, 2008)
to the
Rate Schedule TF-1 Service Agreement
(Contract No. 136455)
between Northwest Pipeline GP
and Northwest Natural Gas Company

SERVICE DETAILS

1. Transportation Contract Demand (CD): 12,000 Dth per day

2. Primary Receipt Point (s) :

Point ID Name	Maximum Daily Quantities (Dth)
503 GREASEWOOD	1300
543 OPAL PLANT	5700
700 COLLINS GULCH	5000
Total	12000

3. Primary Delivery Point (s) :

Point ID Name	Maximum Daily Delivery Obligation (Dth)
284 SEDRO/WOOLLEY	12000
Total	12000

4. Customer Category:

   a. Large Customer

   b. Incremental Expansion Customer: No

5. Recourse or Discounted Recourse Transportation Rates:

   a. Reservation Charge (per Dth of CD):
   Maximum Base Tariff Rate, plus applicable surcharges

   b. Volumetric Charge (per Dth):
   Maximum Base Tariff Rate, plus applicable surcharges

   c. Additional Facility Reservation Surcharge Pursuant to Section 3.4 of Rate Schedule TF-1 (per Dth of CD): None

   d. Rate Discount Conditions Consistent with Section 3.5 of Rate Schedule TF-1:

   Not Applicable

6. Transportation Term:

   a. Primary Term Begin Date:
   January 01, 2017

   b. Primary Term and Date:
   December 31, 2046

c. Evergreen Provision:
Yes, standard bi-lateral evergreen under Section 12.2 of Rate Schedule TF-1

7. Contract Specific OFO Parameters: None.

8. Regulatory Authorization: 18 CFR 284.223

9. Additional Exhibits:
Exhibit B No
Exhibit C No
Exhibit D No

Section 4: EX-10.J(9) (AGREEMENT BETWEEN THE COMPANY AND MARCH POINT COGENERATION COMPANY)

Exhibit 10j. (9)

AGREEMENT
BETWEEN
MARCH POINT COGENERATION COMPANY AND NORTHWEST NATURAL GAS COMPANY

This AGREEMENT ("Agreement"), dated and made effective as of February 8, 2008 is by and between MARCH POINT COGENERATION COMPANY, a California general partnership ("MPCC"), having a place of business at 8507 S. Texas Road, Anacortes, WA 98221 and NORTHWEST NATURAL GAS COMPANY, an Oregon corporation, having a place of business at 220 NW 2nd Ave., Portland, OR 97209 ("NW NATURAL").

WITNESSETH:

WHEREAS, Northwest Pipeline GP ("NWPL") has offered MPCC a right of first refusal ("ROFR") to extend MPCC's existing capacity on NWPL's pipeline under Contract No. 100055 for a primary term from January 1, 2012 through December 31, 2046, and

WHEREAS, MPCC (a) has no commercial need or interest in such capacity from the period January 1, 2017 through December 31, 2046 (the "Second Period") and (b) may have no commercial need or interest in such capacity from the period January 1, 2012 through December 31, 2016 (the "First Period"), and

WHEREAS, NW NATURAL desires to assume said capacity rights as provided for herein.

NOW, THEREFORE, based upon the mutual promises and the terms, conditions, obligations, warranties and covenants in this Agreement, the parties hereto agree as follows:

1. **Mutual Undertakings.**

A. MPCC and NW Natural each hereby acknowledges and agrees that MPCC may, but is not obligated to, exercise the ROFR offer from NWPL to continue its existing capacity rights to 12,000 MMBtu/D of TF-1 capacity for the period from January 1, 2012 through December 31, 2046 (hereafter, the "Capacity Rights").

B. MPCC and NW NATURAL further agree that if MPCC successfully exercises its ROFR pursuant to Section 1A, above, (i) MPCC will immediately permanently release such Capacity Rights for the Second Period to NW NATURAL, pursuant to NWPL's permanent capacity release tariff requirements, via the NWPL electronic bulletin board, and NW NATURAL will accept such permanent release of and will assume the Capacity Rights for the Second Period; and (ii) if MPCC subsequently determines, in its sole discretion, that it will have no requirements for all or any portion of the Capacity Rights for the First Period (up to 12,000 MMBtu/D and up to any remaining time in the First Period) (the "Surplus Capacity Rights"), upon reasonable prior notice to NW NATURAL given to NW NATURAL no later than June 30, 2009, MPCC will permanently release such Surplus Capacity Rights to NW NATURAL, pursuant to NWPL's capacity release requirements, via the NWPL electronic bulletin board and NW NATURAL will accept such permanent release of and will assume the Surplus Capacity Rights. If MPCC does not provide the notice set forth in the previous sentence with respect to the Surplus Capacity Rights by June 30, 2009, NW NATURAL will have no obligation to assume such Surplus Capacity Rights and MPCC will have no obligation to permanently release such Surplus Capacity Rights to NW NATURAL.

C. Upon the effective date of the permanent capacity release, NW NATURAL agrees to assume and be responsible for, and shall perform, pay and discharge all duties, obligations and liabilities of any nature (including all financial responsibilities and tariff obligations) with respect to: (i) the Capacity Rights for the Second Period; and, if applicable, (ii) the Surplus

C. The parties may also mutually agree to utilize the service of a mediator pursuant to a joint engagement.

D. If a dispute or disputes involving the rights and obligations of the parties to this Agreement, including any question regarding its existence, validity or termination, cannot be settled by negotiation or mediation as referred to above, it shall be finally resolved by arbitration. Within sixty (60) days (unless otherwise extended by mutual agreement of the parties) after receipt of the written Notice of Dispute, any such claim shall be submitted for binding arbitration in accordance with the then current Rules for Non-Administered Arbitration of the International Institute for Conflict Prevention & Resolution and this provision. The arbitration shall be governed by the United States Arbitration Act, 9 U.S.C. §§ 1-16 to the exclusion of any provision of state law inconsistent therewith or which would produce a different result. Judgment upon the award rendered by the arbitrator may be entered by any court having jurisdiction. The arbitration shall be held in a location as may be mutually convenient and agreed to in writing by the parties. The parties shall attempt to agree upon a single arbitrator within five (5) business days following the receipt of notice to begin arbitration proceedings. If the parties fail agree upon an arbitrator, then each party shall appoint an arbitrator and the two arbitrators shall select a third arbitrator within fifteen (15) days of the request for the arbitration. The arbitrator(s) shall be qualified to decide the matter in dispute, with some experience and knowledge of the energy industry. The arbitrator(s) shall not be a current or former director, officer, employee, or agent of either party, or the beneficial owner of any interest or common stock of either party, any affiliate of either party, or a partner or employee of a law firm that has represented either party within the two (2) years preceding the invocation of arbitration, unless disclosed and waived by the parties. The arbitrator shall set forth the reasons for the award in writing. The terms hereof shall not limit any obligation of a party to defend, indemnify or hold harmless another party against court proceedings or other claims, losses, damages, or expenses and in such event an ancillary dispute between the parties which arises out of the claim may be resolved in such forum.

E. Pending the completion of any arbitration proceedings, obligations not in dispute shall continue to be performed.

6. Entirety of Agreement. This Agreement contains the entire agreement between the parties hereto with respect to the subject matter hereof and supersedes all prior agreements and undertakings between the parties hereto relating to the subject matter hereof. No course of prior dealings between the parties or their predecessors shall be relevant to supplement or explaining any terms used herein.

7. Severability. This Agreement is subject to all applicable federal and state laws and nothing herein is intended to violate any such law. If any clause or provision of this Agreement is held to by invalid or unenforceable by any court, the invalidity or unenforceability of such clause or provision shall not affect the remaining provisions of this Agreement, and this Agreement shall be construed and enforced as if such invalid or unenforceable clause or provision had not been contained in this Agreement.

8. **Counterparts.** This Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original, but all of which together shall constitute one and the same instrument. A facsimile version of the signature page shall have the same legal effect as an original.

IN WITNESS WHEREOF, the parties hereto have executed and delivered this Agreement as of the day and year first above written.

MARCH POINT COGENERATION COMPANY

BY: Thomas M. McMaster

TITLE: EXEC, DIR

DATE: 2/8/08

NORTHWEST NATURAL GAS COMPANY

BY: R.S.J.

TITLE: Director, Gas Supply

DATE: 2/8/08

Section 5: EX-12 (STATEMENT RE COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES.)

EXHIBIT 12

NORTHWEST NATURAL GAS COMPANY
Statement Re: Ratio of Earnings to Fixed Charges
Thousands, except per share amounts
(Unaudited)

	Year Ended December 31,				
	2007	2006	2005	2004	2003
Fixed Charges, as defined:					
Interest on Long-Term Debt	$ 34,294	$ 34,651	$ 34,330	$ 33,776	$ 33,258
Other Interest	4,116	4,648	2,665	2,184	2,048
Amortization of Debt Discount and Expense	711	716	808	773	696
Interest Portion of Rentals	1,523	1,465	1,357	1,489	1,622
Total Fixed Charges, as defined	$ 40,644	$ 41,480	$ 39,160	$ 38,222	$ 37,624
Earnings, as defined:					
Net Income	$ 74,497	$ 63,415	$ 58,149	$ 50,572	$ 45,983
Taxes on Income	44,060	36,234	32,720	26,531	23,340
Fixed Charges, as above	40,644	41,480	39,160	38,222	37,624
Total Earnings, as defined	$ 159,201	$ 141,129	$ 130,029	$ 115,325	$ 106,947
Ratio of Earnings to Fixed Charges	3.92	3.40	3.32	3.02	2.84

Section 6: EX-23 (CONSENT OF PRICEWATERHOUSECOOPERS LLP.)

EXHIBIT 23

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 33-63017, 333-46430, 333-55002, 333-70218, 333-100885, 333-120955, 333-134973 and 333-139819) and in the Registration Statements on Form S-3 (Nos. 333-148527 and 333-123898) of Northwest Natural Gas Company of our report dated February 29, 2008 relating to the consolidated financial statements, financial statement schedule and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Portland, Oregon
February 29, 2008

Section 7: EX-31.1 (SECTION 302 CERTIFICATION PRINCIPAL EXECUTIVE OFFICER)

EXHIBIT 31.1

CERTIFICATION

I, Mark S. Dodson, certify that:

1. I have reviewed this annual report on Form 10-K of Northwest Natural Gas Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
   - (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
   - (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
   - (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
   - (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):
   - (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   - (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 29, 2008

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

Section 8: EX-31.2 (SECTION 302 CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER)

EXHIBIT 31.2

CERTIFICATION

I, David H. Anderson, certify that:

1. I have reviewed this annual report on Form 10-K of Northwest Natural Gas Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 29, 2008

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

Section 9: EX-32.1 (SECTION 906 CERTIFICATIONS)

EXHIBIT 32.1

NORTHWEST NATURAL GAS COMPANY
Certificate Pursuant to Section 906
of Sarbanes – Oxley Act of 2002

Each of the undersigned, MARK S. DODSON, the Chief Executive Officer, and DAVID H. ANDERSON, the Senior Vice President and Chief Financial Officer, of NORTHWEST NATURAL GAS COMPANY (the Company), DOES HEREBY CERTIFY that:

1. The Company's Annual Report on Form 10-K for the year ended December 31, 2007 (the Report) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and
2. Information contained in the Report fairly presents, in all material respects, the financial condition and results of operation of the Company.

IN WITNESS WHEREOF, each of the undersigned has caused this instrument to be executed this 29th day of February 2008.

/s/ Mark S. Dodson
Chief Executive Officer

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

A signed original of this written statement required by Section 906 has been provided to Northwest Natural Gas Company and will be retained by Northwest Natural Gas Company and furnished to the Securities and Exchange Commission or its staff upon request.

Section 10: EX-10.B (EXECUTIVE SUPPLEMENTAL RETIREMENT INCOME PLAN (2007 RESTATEMENT))

Exhibit 10b.

NORTHWEST NATURAL GAS COMPANY

EXECUTIVE SUPPLEMENTAL RETIREMENT INCOME PLAN

(2007 Restatement)

NORTHWEST NATURAL GAS COMPANY
EXECUTIVE SUPPLEMENTAL RETIREMENT INCOME PLAN
(2007 RESTATEMENT)

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NORTHWEST NATURAL GAS COMPANY

EXECUTIVE SUPPLEMENTAL RETIREMENT INCOME PLAN

(2007 RESTATEMENT)

PURPOSE; EFFECTIVE DATE

This Executive Supplemental Retirement Income Plan ("Plan") was established effective January 1, 1981, and was later amended, to promote the best interests of the Company by enabling the Company (a) to attract to its key management positions persons of outstanding ability, and (b) to retain in its employ those persons of outstanding competence who occupy key executive positions and who in the past contributed and who continue in the future to contribute materially to the success of the business by their ability, ingenuity and industry. Participation in the Plan is limited to a select group of management and highly compensated employees. Effective September 1, 2004, participation is limited to Participants in the Plan as of September 1, 2004, and no new Participants will be added to the Plan after September 1, 2004. In order to comply with changes in applicable law and to clarify existing provisions, the Company adopts this 2007 Restatement on December 20, 2007 with a retroactive effective date of January 1, 2005; provided, however, that the amendments made in this 2007 Restatement shall not apply to any Participant whose Separation from Service occurred prior to January 1, 2005 and the benefits for those Participants shall be governed by the terms of the Plan in effect immediately prior to this 2007 Restatement.

ARTICLE I. DEFINITIONS

The following words and phrases as used herein shall, for the purpose of this Plan and any subsequent amendment thereof, have the following meanings, unless a different meaning is plainly required by the context:

1.01 Benefit Commencement Date means the first day of the month in which Plan benefits are required to commence as provided under 3.02.

1.02 Board of Directors means the Board of Directors of the Company as constituted from time to time.

1.03 Change in Control Severance Benefit means, for any Participant who is party to a Change in Control Severance Agreement with the Company, the severance benefit provided for in such agreement; provided, however, that such severance benefit is a "Change in Control Severance Benefit" for purposes of this Plan only if, under the terms of the Participant’s Change in Control Severance Agreement, the Participant becomes entitled to the severance benefit (a) after a change in control of the Company has occurred, (b) because the Participant’s employment with the Company has been terminated by the Participant for good reason in accordance with the terms and conditions of the Change in Control Severance Agreement or by the Company other than for cause or disability, and (c) because the Participant has satisfied any other conditions or requirements specified in the Change in Control Severance Agreement and necessary for the Participant to become entitled to receive the severance benefit. Under no circumstances will a Participant who is not party to a Change in Control Severance Agreement be deemed to become entitled to a Change in Control Severance Benefit for purposes of this Plan. For purposes of 1.03, the terms "change in control," "good reason," "cause" and "disability" shall have the meanings as may be set forth in the Participant's Change in Control Severance Agreement, if any.

1.04 Committee means the Organization and Executive Compensation Committee of the Board of Directors, previously known as the Compensation Committee.

1.05 Company means Northwest Natural Gas Company and its subsidiaries.

1.06 Effective Date means January 1, 1981, subject to any later effective date of any specific section provided in any amendment hereto.

1.07 Final Annual Compensation means the annual average determined by taking the sum of the Participant's Total Compensation for the three (3) consecutive Compensation Years out of the Participant's final ten (10) Compensation Years with the Company which produce the highest three (3) year total amount, and dividing such sum by three (3).

1.07-1 Total Compensation for any Compensation Year means the sum of (a) plus (b):

(a) The annual salary approved by the Board of Directors and in effect during the Compensation Year; provided, however, that if a Participant's salary is changed during a Compensation Year, the salary amount included in Total Compensation for that Compensation Year shall be the total amount of salary the Participant earned for services during that Compensation Year or would have earned for services during that Compensation Year if employment had continued at his or her final salary level for the full Compensation Year.

(b) The annual performance award for the prior calendar year approved by the Board of Directors by the beginning of the Compensation Year; provided, however, that if a Participant has a Separation from Service during the last 61 days of any Compensation Year, Total Compensation for each of the Participant's final ten (10) Compensation Years shall also be calculated as the sum of the salary in effect for such Compensation Year as determined under (a) plus the annual performance award for the calendar year that ended during such Compensation Year, and these alternate Total Compensation calculations shall be used if the resulting Final Average Compensation is higher.

1.07-2 Compensation Year means the twelve (12) month period from March 1 to February 28/29, including any partial portion of such period preceding a Separation from Service.

1.08 Normal Retirement Date means the first day of the month next following the Participant’s 65th birthday.

1.09 Participant means an employee specifically designated by the Committee to be covered under this Plan and who continues to fulfill all requirements for participation. The initial designation of Participants shall be all executive officers of the Company elected by the Board of Directors (not including "assistant" officer positions). A list of Participants as of September 1, 2004 who were employed by the Company as of that date is included in the 2004 ESRIP Appendix. No new Participants shall enter the Plan after September 1, 2004.

1.10 Plan means the Executive Supplemental Retirement Income Plan herein set forth, as amended from time to time.

1.11 Retirement Plan means the Company’s Retirement Plan for Non-Bargaining Unit Employees, as amended from time to time.

1.12 Separation from Service shall have the meaning ascribed to such term in Treasury Regulations §1.409A-1(h).

1.13 Service depends on the context:

(a) Benefit Accrual. Service for benefit accrual under 2.01 means years of actual participation, including service credited under 1.13(c), after becoming a Participant under this Plan, plus any additional years of benefit accrual credit earned or awarded under 2.01-2(b)(2) and/or (3).

(b) Vesting Service. Service for vesting means all service with the Company from commencement of employment, including service credited under 1.13(c), plus any additional grant under 2.05-5.

(c) Other Service. To the extent "service" is not addressed by (a) or (b) above, Service includes all accredited years of service with the Company credited under the Retirement Plan and includes all periods of Company paid disability and long-term disability leave.

1.14 Surviving Beneficiary means the beneficiary or beneficiaries designated by the Participant on the form provided by the Company. Such beneficiary designation may be changed by the Participant at any time by written notice to the Committee. If no Surviving Beneficiary is designated, or if the designated Surviving Beneficiary dies before the Benefit Commencement Date, the Surviving Beneficiary shall be the Participant’s surviving spouse or, if none, the Participant’s estate.

1.15 Total and Permanent Disability means that the Participant is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than 12 months.

ARTICLE II. AMOUNT OF BENEFITS; RIGHT TO RECEIVE BENEFITS

Each Participant or the Participant's Surviving Beneficiary shall have the right to receive, and the Company shall pay, supplemental benefits as provided in this Article II, in the form and at the time provided in Article III:

2.01 Normal Retirement Supplemental Income. Upon Separation from Service at or after the Normal Retirement Date with at least ten (10) years of Service for vesting under 1.13(b), a Participant shall be entitled to receive, subject to 2.07, monthly supplemental retirement payments determined under 2.01-1 through 2.01-4:

2.01-1 Determining ESRIP Benefit Amount. The amount to be paid at the Normal Retirement Date under this Plan shall be determined by a three step process under the following (a), (b) and (c):

(a) Determine Target Benefit. The sum of the Participant's accrued target percentage credits under 2.01-2 is multiplied by Final Annual Compensation.

(b) Determine Offset Amount. The amount to be paid at Normal Retirement Date from three other sources of retirement benefits shall be determined under 2.01-3.

(c) Determine Net Benefit. If the target benefit amount under (a) exceeds the total payments from the other three sources under (b), the excess shall be paid under 2.01-4.

2.01-2 Accrued Target Percentage. Participant's accrued target percentage shall be the sum of the accruals at the rate specified below in (a) for each Year of Participation (defined below in (b)) credited under this Plan.

(a) Yearly Accrual Percentage Schedule:

(1) Years 1-15. The yearly target percentage accrual for all Participants shall be:

Years of Participation	**Accrued Target Percentage for Each Year of Participation**	**Maximum Total Target Percentage**
Years 1 through 15	4.33% per Year	65% (15 Years times 4.33%)

(2) Years 16-25. In addition, each of the Participants who had at least six (6) Years of Participation as of September 1, 2004 as shown in the attached 2004 ESRIP Appendix shall be entitled to additional accruals for Years of Participation 16-25 as follows:

Years of Participation	**Accrued Target Percentage for Each Year of Participation**	**Maximum Total Target Percentage**
Years 16 through 25	0.50% per Year	70% (15 Years times 4.33% plus 10 Years times 0.50%)

(b) Year of Participation means the sum of (1), (2) and (3):

(1) Each consecutive twelve (12) month period (including fractions calculated to the nearest hundredth of a year) of Service measured by each anniversary of the date of first becoming a Participant under this Plan.

(2) Any additional Years of Participation awarded to a Participant by the Committee in the exercise of its discretion, specifically including any additional Years of Participation reflected in the attached 2004 ESRIP Appendix as of September 1, 2004.

(3) Three (3) additional Years of Participation credit shall be awarded to any Participant who becomes entitled to a Change in Control Severance Benefit.

2.01-3 Payments From Other Sources. The total annual payments from the three sources listed below in (a), (b) and (c) shall be determined, all calculated as a single life annuity.

(a) the Retirement Plan.

(b) Social Security (as determined under 2.01-4(b)(2)).

(c) Supplemental retirement payments under Section 5.7 of the Company’s Executive Deferred Compensation Plan and Section 8 of the Company’s Deferred Compensation Plan for Directors and Executives.

2.01-4 Benefit Payable Under This Plan. The monthly payment under this Plan shall be determined under the formula of (a) minus (b) as follows:

(a) The target monthly benefit shall be one-twelfth (1/12) times Final Annual Compensation times the accrued target percentage determined under 2.01-2 above;

MINUS

(b) The sum of (1) plus (2) plus (3):

(1) The Participant’s monthly retirement benefit under the Retirement Plan assuming commencement of benefits in the month following Separation from Service and calculated as if the Participant had elected to have the entire benefit paid as a single life annuity;

PLUS

(2) One-twelfth (1/12) of the Participant’s annual primary Social Security benefit assuming commencement of benefits in the month following Separation from Service and determined in the same manner and based on the same earnings as are used to compute the actual Social Security benefit;

PLUS

(3) The Participant’s monthly supplemental retirement benefit under Section 5.7 of the Company’s Executive Deferred Compensation Plan and/or Section 8 of the Company’s Deferred Compensation Plan for Directors and Executives, calculated in each case as if the Participant had elected to have the benefit paid as a single life annuity.

2.02 Early Retirement Supplemental Income. Upon Separation from Service at or after age fifty-five (55) with at least ten (10) years of Service for vesting under 1.13(b), a Participant shall be entitled to receive, subject to 2.07, the reduced monthly supplemental retirement payments determined as follows:

2.02-1 First, the target monthly early retirement benefit shall be equal to one-twelfth (1/12) times the Participant’s Final Annual Compensation times the accrued target percentage determined under 2.01-2 based on the Participant’s Years of Participation at the time of Separation from Service.

2.02-2 Second, the unreduced monthly supplemental payment under this Plan shall be determined under the formula in 2.01-4, using in 2.01-4(b)(1) the Participant’s monthly retirement benefit under the Retirement Plan assuming commencement of benefits in the month following the Participant’s Normal Retirement Date and a projected 2.5% annual increase in the Consumer Price Index between Separation from Service and Normal Retirement Date and calculated as if the Participant had elected to have the entire benefit paid as a single life annuity, using in 2.01-4(b)(2) the Participant’s estimated monthly Social Security benefit payable at age 65 assuming no earnings after Separation from Service and no projected increases in the national average wage index or cost of living between Separation from Service and age 65, and using in 2.01-4(b)(3) the Participant’s monthly retirement benefit under Section 5.7 of the Company’s Executive Deferred Compensation Plan and/or Section 8 of the Company’s Deferred Compensation Plan for Directors and Executives, calculated in each case assuming that benefits could have been and were commenced in the month following the Participant’s Normal Retirement Date and as if the Participant had elected to have the benefit paid as a single life annuity.

2.02-3 Third, the unreduced monthly amount under 2.02-2 shall be reduced by one-half of one percent (0.50%) per month for each full or partial month by which the Benefit Commencement Date precedes the Participant's 62nd birthday, as illustrated in the following table:

Percentage of Unreduced Early Retirement Benefit for Benefit Commencement at Specified Age*

Retirement Age	Percentage
55	58%
56	64%
57	70%
58	76%
59	82%
60	88%
61	94%
62-64	100%

* This table shows the percentage reduction based on years prior to age 62. The actual percentage reduction will be further adjusted for each additional month by which the Participant's age at the Benefit Commencement Date precedes the retirement age specified in the table.

2.03 Disability Retirement Supplemental Income. Upon a Participant's Total and Permanent Disability while employed by the Company and with at least fifteen (15) years of Service for vesting under 1.13(b) and 1.13(c), a Participant shall be entitled to receive, subject to 2.07, monthly supplemental retirement payments determined in the same manner as early retirement payments under 2.02.

2.04 Death Benefits. If a Participant dies during employment or before the Benefit Commencement Date for any other benefit under this Plan, a monthly supplemental death benefit shall be paid to the Participant's Surviving Beneficiary as follows:

2.04-1 Amount. The amount of the monthly supplemental death benefit shall be determined under either 2.01, 2.02, 2.03, 2.05 or 2.08, as applicable, assuming that (a) the Participant had a Separation from Service on the date of death (or on the Participant's actual Separation from Service, if earlier), (b) the Participant had survived until the Benefit Commencement Date that would have been applicable under 3.02 based on the assumed date of Separation from Service, (c) the Participant had selected the form of annuity selected by the Surviving Beneficiary pursuant to 2.04-2, and (d) the Participant had died on the day after the Benefit Commencement Date.

2.04-2 Annuity Form. The Surviving Beneficiary may at any time prior to the applicable Benefit Commencement Date elect one of the available annuity forms under 3.01 for purposes of calculating and paying the death benefit under 2.04-1. If the Surviving Beneficiary does not make a timely election under this 2.04-2, the Surviving Beneficiary shall be deemed to have elected a 100% joint and survivor annuity (without the "pop-up" feature) if the Surviving Beneficiary is one individual; otherwise, the Surviving Beneficiary shall be deemed to have elected the life annuity with 120 guaranteed payments under 3.01-1.

2.04-3 Other Death Benefits. The supplemental death benefit under this Plan shall be in addition to any death benefit provided by any other Company sponsored plan or insurance program.

2.05 Vested Benefits. Upon Separation from Service with at least five (5) years of Service for vesting under 1.13(b), a Participant who is not eligible for benefits under 2.01, 2.02, 2.03 or 2.08, shall be entitled to receive, subject to 2.07, the reduced monthly supplemental retirement payments determined as follows:

2.05-1 First, the unreduced monthly supplemental payment under this Plan shall be determined in the same manner as such amount would be determined for early retirement payments under 2.02-1 and 2.02-2, except that in 2.01-4(b)(2) there shall be used the Participant's estimated monthly Social Security benefit payable at age 65 assuming continuation of earnings after Separation from Service through age 65 at the Participant's final salary level with the Company, but with no projected increases in the national average wage index or cost of living between Separation from Service and age 65.

2.05-2 Second, the vested portion of the unreduced monthly amount shall be determined by multiplying the unreduced monthly amount by the vested percentage set forth in the following table that corresponds to the Participant's number of years of Service for vesting under 1.13(b):

Completed Years of Vesting Service	Vested Percentage
Years 1-4	0%
Year 5	50%
Year 6	60%
Year 7	70%
Year 8	80%
Year 9	90%
Year 10 and above	100%

2.05-3 Third, if the Participant's Separation from Service occurs before age fifty-five (55), the vested portion of the unreduced monthly amount under 2.05-2 shall be reduced by one-half of one percent (0.50%) per month for each full or partial month by which the Benefit Commencement Date precedes the Participant's 65th birthday, as illustrated in the following table:

Percentage of Unreduced Vested Retirement Benefit for Benefit Commencement at Specified Age

Commencement Age	Percentage
55	40%
56	46%
57	52%
58	58%
59	64%
60	70%
61	76%
62	82%
63	88%
64	94%

If the Participant's Separation from Service occurs at or after age 55, the vested portion of the unreduced monthly amount under 2.05-2 shall be reduced in the same manner as provided under 2.02-3 for early retirement benefits.

2.05-4 Vesting Service Credit. One year of vesting service is awarded for each period of 12 consecutive months of employment with the Company, with the first such period beginning on the Participant's employment commencement date and subsequent periods beginning on each anniversary of the Participant's employment commencement date.

2.05-5 Committee Discretion. For any specified Participant, the Committee may, in its discretion, grant additional vesting service credit, waive the minimum service requirement, reduce the early retirement reduction percentage for payments starting before age 65, or make any appropriate adjustment of the benefit amount under this Plan.

2.06 Post-Retirement Change in Retirement Plan Benefits.

2.06-1 Change in Benefit Formula. If, after supplemental payments start under this Plan, the benefit payable to a retired Participant is increased under the Retirement Plan by a change in the Retirement Plan benefit formula or its components, the supplemental payment under this Plan shall be reduced to reflect such increase, effective for and after the first month when such increase is paid. The supplemental benefit shall be recalculated under the benefit formula (2.01, 2.02, 2.03, 2.04, 2.05 or 2.08) applicable to the retiree by substituting such increased Retirement Plan benefit in the formula, with all other components of the formula to remain unchanged.

2.06-2 COLA Supplement. Any post-retirement increase to the Retirement Plan benefit that is not the result of a change of the Retirement Plan benefit formula or its components (such as a cost of living adjustment for retirees) shall not trigger a recalculation of benefits under 2.06-1 of this Plan.

2.07 Forfeiture of Benefits. Notwithstanding any other provision of this Plan to the contrary, Plan benefits shall be forfeited as follows:

2.07-1 Discharge for Cause. No Plan benefits shall be paid if the Participant is discharged from the Company for cause involving illegal or fraudulent acts or conduct detrimental to the interests of the Company.

2.07-2 Agreement Not to Compete. No Plan benefits shall be paid to a Participant unless, prior to the date Plan benefits are scheduled to commence, the Company receives Participant's written agreement not to compete with the Company or its subsidiaries during the period of Plan benefit payments. Plan benefits shall be forfeited in whole or in part, as the Committee shall decide, for any breach of such agreement not to compete.

2.08 Change in Control Supplemental Income.

2.08-1 Benefit Calculation. A Participant who has a Separation from Service before the Normal Retirement Date and is or becomes entitled to a Change in Control Severance Benefit shall have a 100% vested right to receive, subject to 2.07, monthly supplemental retirement payments determined in the same manner as early retirement payments under 2.02, except that (a) the Participant shall be credited with additional Years of Participation as provided in 2.01-2(b)(3), and (b) in lieu of applying 2.02-3, the unreduced monthly amount under 2.02-2 shall be reduced by one-quarter of one percent (0.25%) per month for each full or partial month by which the Benefit Commencement Date precedes the Participant's 62nd birthday.

2.08-2 Possible Benefit Recalculation. With respect to any Participant who is party to a Change in Control Severance Agreement, it may be the case that (a) the Participant's employment with the Company is terminated prior to a "change in control" of the Company (as defined in the Participant's Change in Control Severance Agreement), (b) a change in control of the Company occurs after such termination, and (c) the Participant then becomes entitled to a Change in Control Severance Benefit. If, after such termination of employment and prior to the time that the Participant becomes entitled to a Change in Control Severance Benefit, supplemental benefit payments to the Participant have started under the Plan, then, at such time thereafter as the Participant becomes entitled to a Change in Control Severance Benefit, the benefits payable to the Participant under the Plan shall be retroactively recalculated to reflect the benefit enhancements applicable under the Plan as a result thereof. To the extent that the amount of the supplemental benefit payments paid to the Participant prior to such recalculation is less than the amount of such payments as so recalculated, the difference will be paid to the Participant in a cash lump sum (without interest) as soon as practicable after the change in control of the Company.

ARTICLE III. PAYMENT OF BENEFITS

3.01 Form of Supplemental Payments. Subject to 3.01-3, supplemental monthly payments to a Participant shall be made in the annuity form specified in 3.01-1; provided, however, that a Participant may elect at any time at least 30 days prior to the Benefit Commencement Date to have benefit payments made in one of the annuity forms specified in 3.01-2:

3.01-1 Life Annuity With One Hundred Twenty (120) Guaranteed Payments. Unless the Participant elects another annuity form under 3.01-2 , the Participant's monthly supplemental benefit as determined under 2.01, 2.02, 2.03, 2.05 or 2.08 shall be paid as equal monthly payments for the Participant's lifetime, except that if the Participant dies before receiving one hundred twenty (120) monthly payments, the balance of the one hundred twenty (120) payments shall be made monthly to the Participant's Surviving Beneficiary.

3.01-2 Annuity Forms under Retirement Plan. The Participant may elect to receive supplemental monthly payments in any of the standard or optional annuity forms of benefit described in 6.01 and 6.02 of the Retirement Plan, other than a joint and survivor annuity upon marriage or remarriage after the annuity starting date. Any such alternate annuity shall be the actuarial equivalent of the benefit under 3.01-1 as determined by the Plan's actuary based on the actuarial assumptions used for determining equivalent benefits under the Retirement Plan at the Benefit Commencement Date.

3.01-3 Small Benefit Cash Out. If the actuarial equivalent lump sum present value of a Participant's benefits, based on the actuarial assumptions used for determining equivalent benefits under the Retirement Plan at the Benefit Commencement Date, is no more than the applicable dollar amount under Internal Revenue Code section 402(g)(1)(B) (which is $15,500 in 2007 and 2008), the benefit shall be paid as a lump sum in such amount at the time annuity payments would have otherwise commenced under 3.02.

3.02 Commencement of Supplemental Payments.

3.02-1 Normal Retirement Supplemental Income. If a Participant is eligible for normal retirement benefits under 2.01, supplemental monthly payments under this Plan shall commence with the first month following the Participant's Separation from Service.

3.02-2 Change in Control Supplemental Income. If a Participant is not eligible for normal retirement benefits under 2.01, but is eligible for change in control retirement benefits under 2.08, supplemental monthly payments under this Plan shall commence with the first month following the later of the Participant's 55th birthday or the Participant's Separation from Service.

3.02-3 Disability Retirement Supplemental Income. If a Participant is not eligible for normal retirement benefits under 2.01 or change in control retirement benefits under 2.08, but is eligible for disability retirement benefits under 2.03, supplemental monthly payments under this Plan shall commence with the first month following the later of the Participant's 55th birthday or the Participant's Total and Permanent Disability; provided, however, that a Participant may elect no later than December 31, 2008 to have any disability retirement benefits commence under this 3.02-3 with the first month following the later of the Participant's Separation from Service or another specified birthday of the Participant that shall be no less than age 56 and no more than age 62.

3.02-4 Early Retirement Supplemental Income. If a Participant is not eligible for normal retirement benefits under 2.01, change in control retirement benefits under 2.08 or disability retirement benefits under 2.03, but is eligible for early retirement benefits under 2.02, supplemental monthly payments under this Plan shall commence with the first month following the later of the Participant's 62nd birthday or the Participant's Separation from Service; provided, however, that a Participant may elect no later than December 31, 2008 to have any early retirement benefits commence under this 3.02-4 with the first month following the later of the Participant's Separation from Service or another specified birthday of the Participant that shall be no less than age 55 and no more than age 61.

3.02-5 Vested Benefits. If a Participant is not eligible for normal retirement benefits under 2.01, change in control retirement benefits under 2.08, disability retirement benefits under 2.03 or early retirement benefits under 2.02, but is eligible for vested benefits under 2.05, supplemental monthly payments under this Plan shall commence with the first month following the later of the Participant's 65th birthday or the Participant's Separation from Service; provided, however, that a Participant may elect no later than December 31, 2008 to have any vested benefits commence under this 3.02-5 with the first month following the later of the Participant's Separation from Service or another specified birthday of the Participant that shall be no less than age 55 and no more than age 64.

3.02-6 Death Benefits. If a Participant's Surviving Beneficiary is eligible for death benefits under 2.04, supplemental monthly payments under this Plan shall commence in the month that benefits would have commenced under 3.02-1, 3.02-2, 3.02-3, 3.02-4 or 3.02-5, as applicable, if the Participant had a Separation from Service on the date of death (or on the Participant's actual Separation from Service, if earlier) and then survived until benefits had commenced.

3.03 Six-Month Minimum Delay. Notwithstanding the foregoing, no supplemental monthly payments under this Plan shall be paid to any Participant until the seventh month following the month of the Executive's Separation from Service with the Company; provided, however, that this delay in commencement of benefits shall not apply to death benefits under 2.04. Any payments that would have been paid if not for this 3.03 shall be accumulated and paid in full in the seventh month following the month of the Participant's Separation from Service with the Company together with interest from the date each payment otherwise would have been payable until the date actually paid. Interest for any period will be paid at the same rate applicable for that period under Section 6(f) of the Company's Deferred Compensation Plan for Directors and Executives.

3.04 Source. The commitment of the Company to pay supplemental retirement benefits under this Plan is an unsecured promise of the Company to make the payments. There is no asset or trust fund set aside for payment of benefits hereunder, except to the extent held under the Company's Umbrella Trust for Executives, which is subject to the claims of the Company's creditors under conditions specified therein.

3.05 Key Man Insurance. The Company shall purchase and own such key man life insurance as it chooses on the life of any Participant. No Participant, nor his or her beneficiaries, heirs, assigns, personal representative or estate, shall have any right to or interest in any such policy or the proceeds payable thereunder on his or her death. On death of the Participant, the proceeds shall be paid to the Company.

ARTICLE IV. ADMINISTRATION

4.01 Committee Discretion. The Committee shall have full power and authority to interpret, construe and administer this Plan, to adopt appropriate procedures, and to make all decisions necessary or proper to carry out the terms of the Plan. The Committee's interpretation and construction hereof, and actions hereunder, including any determination of benefit amount or designation of the person to receive supplemental payments, shall be binding and conclusive on all persons for all purposes. The timetable and procedure for notice of denial of benefit claims and for hearing on review of such denial shall be as set forth in Article XIII of the Retirement Plan, and the Committee shall make such final review and decision. The Company's vice president responsible for human resources shall act as the Committee's agent in administering this Plan. Neither the Company, nor its officers, employees, directors or Committee, nor any member thereof, shall be liable to any person for any action taken or omitted in connection with the interpretation and administration of this Plan.

4.02 Company Right to Amend, Modify or Terminate. The Company, by action of the Board of Directors, reserves the exclusive right to amend, modify, or terminate this Plan in whole or in part without notice to any Participant. No such termination, modification or amendment shall (a) terminate or diminish any rights or benefits accrued by any Participant or Surviving Beneficiary prior thereto, or (b) accelerate the payment of any Plan benefits unless covered by an exception (set forth in regulations or other guidance of the Internal Revenue Service) to the prohibition on acceleration of deferred compensation. In addition, with respect to any Participant who is party to a Change in Control Severance Agreement with the Company, no such termination, modification or amendment during the pendency of a "potential change in control" of the Company (or, if a "change in control" of the Company occurs, during the 24-month period immediately following such change in control) shall, without the written consent of the Participant, terminate or diminish any rights or benefits to which the Participant may be entitled under the Plan. For purposes of 4.02, the terms "potential change in control" and "change in control" shall have the meanings as may be set forth in the Participant’s Change in Control Severance Agreement, if any.

ARTICLE V. GENERAL PROVISIONS

5.01 No Effect on Employment. This Plan shall not be deemed to give any Participant or other person in the employ of the Company any right to be retained in the employment of the Company, or to interfere with the right of the Company to terminate any Participant or such other person at any time. The Company is authorized and empowered to treat the Participant or other person without regard to the effect which such treatment might have under the Plan.

5.02 Legally Binding. The rights, privileges, benefits and obligations under this Plan are intended to be legal obligations of the Company and binding upon the Company, its successors and assigns. The Company agrees it will not be a party to any merger, consolidation or reorganization, unless and until its obligations hereunder shall be expressly assumed by its successor or successors.

5.03 Notice. Any election, notice or filing required or permitted to be given to the Company or the Committee under this Plan shall be sufficient if in writing and hand delivered, or sent by registered or certified mail, to the Secretary of the Company. Such notice shall be deemed given as of the date of delivery or, if delivery is made by mail, as of the date shown on the postmark on the receipt for registration or certification.

5.04 No Transfer of Benefits. The interest of any Participant or beneficiary under this Plan shall not be transferred or transferable, voluntarily or by operation of law, by assignment, anticipation, hypothecation, pledge or other encumbrance, or by garnishment, attachment, levy, seizure or other execution, or by insolvency, receivership, bankruptcy or other debtor proceeding.

5.05 Disclosure to Participants. Each Participant shall receive a copy of this Plan, a copy of any written procedures for administering the Plan, and any amendments to the Plan or procedures.

5.06 Adoption. This Plan was approved by resolution of the Board of Directors at a regular meeting on April 16, 1981, to be effective as of January 1, 1981. Amendments shall take effect as specified in the implementing Board resolution.

5.07 Integration Clause. This written Plan document supersedes, and takes precedence over, any prior oral or written promises to Participants. The Plan may be amended or modified only by a written amendment adopted by the Company's Board of Directors.

SIGNED pursuant to proper authority delegated by the Company's Board of Directors:

NORTHWEST NATURAL GAS COMPANY

By: /s/ Mark S. Dodson
Mark S. Dodson
Chief Executive Officer

Date: February 28, 2008

2004 ESRIP APPENDIX
TO
NORTHWEST NATURAL GAS COMPANY
EXECUTIVE SUPPLEMENTAL RETIREMENT INCOME PLAN
(Effective September 1, 2004)

The following executives are Participants in the Plan as of September 1, 2004. No new Participants will enter the Plan after September 1, 2004. The Participants are entitled to the Years of Participation and Years of Vesting Service shown in the following table, as of September 1, 2004:

Executive	Birth Date	Hire Date	Years of Participation (9/1/04)	Years of Vesting Service (9/1/04)
DeBolt, Bruce R.	12/07/47	2/15/80	24.55	24.55
Dodson, Mark S.	1/26/45	9/15/97	6.96[1]	6.96
Doolittle, Lea Anne	1/12/55	10/30/00	3.83	3.83
Feltz, Stephen P.	8/26/55	10/25/82	5.50	21.83
Kantor, Gregg S.	4/30/57	9/15/96	6.67	7.96
McCoy, Michael S.	5/28/43	11/06/69	34.82	34.82
Rue, Conrad J.	11/25/45	10/29/74	29.85	29.85
Ugoretz, Beth A.	7/11/55	12/06/02	1.66	1.75

[1] Benefits are subject to terms of Board-approved Employment Agreement.

Section 11: EX-10.B(1) (SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN, EFFECTIVE SEPTEMBER 1, 2004)

Exhibit 10b.(1)

NORTHWEST NATURAL GAS COMPANY

SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN

2007 RESTATEMENT

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NORTHWEST NATURAL GAS COMPANY

SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN

2007 RESTATEMENT

1. Purpose; Effective Date. The Board of Directors (the "Board") of Northwest Natural Gas Company (the "Company") adopts this Supplemental Executive Retirement Plan (the "Plan") in order to attract and retain highly effective executives by providing retirement benefits in excess of those provided by the Northwest Natural Gas Company Retirement Plan for Non-Bargaining Unit Employees (the "Qualified Plan"). The Plan shall not apply to executives already covered by the Company’s Executive Supplemental Retirement Income Plan (the "ESRIP"). The Plan is intended to constitute an unfunded plan maintained for the purpose of providing deferred compensation for a select group of management or highly compensated employees. The Plan was adopted effective as of September 1, 2004 (the "Effective Date") and previously restated effective December 1, 2006. In order to comply with changes in applicable law and to clarify existing provisions, the Company adopts this 2007 Restatement effective December 20, 2007, except the changes to the second sentence of 3, to 5(b), and to 6(b) are effective September 1, 2004 as though included in the original Plan.

2. Eligibility. Each executive officer of the Company hired into such office after the Effective Date and each other executive employee of the Company designated by the Organization and Executive Compensation Committee of the Board shall be eligible to participate in the Plan (a "Participant"). "Eligibility Date" means the date as of which the Participant became an executive officer of the Company or the effective date of designation to participate in the Plan, whichever applies. A Participant with an Eligibility Date before December 1, 2006 (a "Tier 1 Participant") shall be provided full benefits under the Plan and a Participant with an Eligibility Date on or after that date (a "Tier 2 Participant") shall be provided with Make-Up Benefits as described in 4(f), 5(d), 6(d), 7(d), and 8(d). Participants in the ESRIP shall not be eligible to participate in the Plan.

3. Years of Participation; Separation from Service. Vesting of benefits, accrual of benefits, and eligibility for retirement shall be based on the Participant’s Years of Participation. "Year of Participation" means a 12-month period elapsed between the Participant’s Eligibility Date and Separation from Service, including fractions of a year for any completed one-month periods. If participation is not continuous, whole and fractional months shall be aggregated and any remaining fractional month shall be disregarded. "Separation from Service", when used in this Plan, shall have the meaning ascribed to such term in Treasury Regulations §1.409A-1(h).

4. Normal Retirement Benefit.

(a) Normal Retirement Date. A Participant’s "Normal Retirement Date" is the first of the month following Separation from Service at or after attainment of age 65 and completion of five Years of Participation.

(b) Amount of Benefit. A Tier 1 Participant’s benefit upon Normal Retirement Date shall be a lump sum equal to six times Final Average Pay (FAP) times the Short Service Factor (SSF) minus the Pension Offset (PO) as follows:

Lump sum = (6 x FAP x SSF) - PO

(c) Final Average Pay. "Final Average Pay" means the annual average determined by taking the sum of the Participant’s Total Compensation for the five (5) consecutive Compensation Years out of the Participant’s final ten (10) Compensation Years with the Company which produce the highest five (5) year total amount, and dividing such sum by five (5).

(i) Total Compensation for any Compensation Year means the sum of (A) plus (B):

(A) The annual salary approved by the Board and in effect during the Compensation Year; provided, however, that if a Participant’s salary is changed during a Compensation Year, the salary amount included in Total Compensation for that Compensation Year shall be the total amount of salary the Participant earned for services during that Compensation Year or would have earned for services during that Compensation Year if employment had continued at his or her final salary level for the full Compensation Year.

(B) The annual performance award for the prior calendar year approved by the Board by the beginning of the Compensation Year; provided, however, that if a Participant has a Separation from Service during the last 61 days of any Compensation Year, Total Compensation for each of the Participant's final ten (10) Compensation Years shall also be calculated as the sum of the salary in effect for such Compensation Year as determined under (A) plus the annual performance award for the calendar year that ended during such Compensation Year, and these alternate Total Compensation calculations shall be used if the resulting Final Average Pay is higher.

(ii) Compensation Year means the twelve (12) month period from March 1 to February 28/29, including any partial portion of such period preceding a Separation from Service.

(d) Short Service Factor. "Short Service Factor" means a percentage calculated by dividing the Tier 1 Participant's Years of Participation at Separation from Service by 15, not to exceed 100 percent.

(e) Pension Offset. "Pension Offset" means a lump sum amount equal to the combined actuarial equivalent value of the following:

(i) The Tier 1 Participant's benefit payable at age 65 under the Qualified Plan in the normal form provided by that plan;

(ii) The make-up benefit payable at age 65 provided by any elective nonqualified deferred compensation plan of the Company (a "Deferred Comp Plan") on account of the reduction in benefits under the Qualified Plan and under Social Security resulting from deferral of compensation under the Deferred Comp Plan; and

(iii) The Tier 1 Participant's Social Security benefit payable at age 65, as estimated by the Committee based on the Tier 1 Participant's total compensation in the most recent full calendar year and an assumed rate of increase over a full working career.

(f) Make-Up Benefit. A Tier 2 Participant's benefit upon Normal Retirement Date shall be equal to the amount, if any, by which the Tier 2 Participant's benefit under the Qualified Plan would be greater than the actual benefit payable under the Qualified Plan upon Normal Retirement Date in the absence of both the following limits:

(i) The limit provided by Section 401(a)(17) of the Internal Revenue Code on compensation counted under the Qualified Plan.

(ii) The limit provided by Section 415(b) of the Internal Revenue Code on benefits payable under the Qualified Plan.

(g) Deferred Compensation. The Tier 2 Participant's Qualified Plan benefit calculated without the limits in (f)(i) and (ii) shall treat salary and bonus deferred by the Tier 2 Participant under the Northwest Natural Gas Company Deferred Compensation Plan for Directors and Executives or the predecessor to such plan as though it had been paid to or received by the Tier 2 Participant in the year when the deferral occurred, but only to the extent such salary and bonus is not counted in the calculation of a supplemental retirement benefit payable to the Tier 2 Participant under Section 8 of such plan.

5. Early Retirement Benefit.

(a) Early Retirement Date. A Participant's "Early Retirement Date" is the first of the month following Separation from Service at or after attainment of age 55 and completion of 15 Years of Participation and before attainment of age 65.

(b) Amount of Benefit. A Tier 1 Participant's benefit upon Early Retirement Date shall be a lump sum determined under the same formula in 4(b) as the benefit at Normal Retirement Date, with the same defined terms, subject to the following additional detail in the definition of Pension Offset. The value of the Qualified Plan benefit and the make-up benefit provided by the Deferred Comp Plan shall be based on the value at age 65 of the benefits payable at age 65, even if those benefits start before age 65. The value of the Social Security benefit shall be determined as of the later of the Tier 1 Participant's Early Retirement Date or the date the Tier 1 Participant will attain age 62 assuming payments commence on that determination date and, if determined as of a future date, based on the assumptions of no earnings after Early Retirement Date and future increases in the national average wage index used to calculate Social Security benefits based on the intermediate assumptions in the most recent report of the Social Security trustees.

(c) Reduction for Commencement Before Age 60. The Tier 1 Participant's benefit upon Early Retirement Date shall be reduced by five percent for each year by which Early Retirement Date precedes the first of the month following the Tier 1 Participant's 60th birthday, with interpolation for a partial year based on one-twelfth of the full five percent for each month.

(d) Make-Up Benefit. A Tier 2 Participant's benefit upon Early Retirement Date shall be the same as the Tier 2 Participant's benefit upon Normal Retirement Date, except the calculation shall be based on the Qualified Plan benefit as of the Early Retirement Date without the limits described in 4(f)(i) and (ii) and based on deferred salary and bonus as provided in 4(g).

6. Termination Benefit.

(a) Vesting. A Participant shall become vested in benefits under the Plan upon completing five Years of Participation, upon suffering a Disability, or when entitled to a Change in Control Severance Benefit as provided in 9(a). A Participant whose employment with the Company terminates prior to vesting shall forfeit any right to benefits under the Plan, subject to reinstatement of such right upon rehire into a position with the Company eligible to participate in the Plan. A Participant whose Separation from Service with the Company occurs after becoming vested and before qualifying for Early or Normal Retirement Date shall be paid a termination benefit.

(b) Amount of Benefit. A Tier 1 Participant's termination benefit shall be determined under the same formula in 4(b) as the benefit at Normal Retirement Date, with the same defined terms, subject to the following additional detail in the definition of Pension Offset. The Pension Offset shall be calculated the same as on Early Retirement Date, except the value of Social Security benefits shall be determined as of the date the Tier 1 Participant will attain age 65 assuming that payments commence on that date and based on the assumptions of future earnings continuing at the Participant's last pay rate with the Company and future cost of living adjustments and increases in the national average wage index used to calculate Social Security benefits based on the intermediate assumptions in the most recent report of the Social Security trustees.

(c) Reduction for Commencement Before Age 60. The Tier 1 Participant's termination benefit shall be reduced by five percent for each year by which the first of the month following Separation from Service precedes the first of the month following the Participant's 60th birthday, with interpolation for a partial year based on one-twelfth of the full five percent for each month. This paragraph (c) shall not reduce the Tier 1 Participant's benefit below 40 percent of the amount payable at age 60.

(d) Make-Up Benefit. A Tier 2 Participant's termination benefit shall be the same as the Tier 2 Participant's benefit upon Normal Retirement Date, except the calculation shall be based on the Qualified Plan benefit, without the limits described in 4(f)(i) and (ii) and based on deferred salary and bonus as provided in 4(g), as of the date the Tier 2 Participant's benefit commences as provided in 7(d).

(e) Disability. "Disability" means a termination of employment because of absence from duties with the Company for 180 consecutive days as a result of the Participant's incapacity due to physical or mental illness or injury, unless within 30 days after a written notice of termination is given following such absence the Participant returns to full-time performance of Company duties.

7. Time and Form of Payment to Participant.

(a) Lump Sum. Except as provided in (b), (c), and (f), benefits shall be paid to a Tier 1 Participant in a lump sum of cash within 30 days following the Tier 1 Participant's Separation from Service.

(b) Optional Annuity Forms. A Tier 1 Participant can receive payment of the Normal Retirement benefit described in Section 4 or the Early Retirement benefit described in Section 5 in any of the standard or optional annuity forms of benefit described in 6.01 and 6.02 of the Qualified Plan, other than a joint and survivor annuity upon marriage or remarriage after the annuity starting date.

(c) Election of Annuity Form. A Tier 1 Participant may elect to receive payment of the benefit amounts described in Sections 4 or 5 in an annuity form of benefit in lieu of a lump sum at any time by delivering written notice of the election to the Committee. The election shall take effect 12 months following the date on which it is delivered to the Committee. If the Tier 1 Participant has a Separation from Service less than 12 months following the date the election is delivered or if the total benefit is no more than the applicable dollar amount under Internal Revenue Code section 402(g)(1)(B) (which is $15,500 in 2007 and 2008), benefits shall be paid in a lump sum. An election to receive an annuity form of benefit must specify a date for commencement of annuity payments that is at least five years after Separation from Service. However, a Tier 1 Participant may elect no later than December 31, 2008, to receive an annuity form of benefit in lieu of a lump sum commencing with the first month following Separation from Service without a five-year delay in commencement and such election shall be effective immediately without a 12-month delay in effectiveness. A Tier 1 Participant who has elected to receive an annuity form of benefit may choose which of the annuity forms described in (b) will be paid, and to change such choice, at any time at least 30 days before the first day of the month in which annuity payments commence. If the Tier 1 Participant does not make a timely election under this 7(c), the annuity benefit shall be paid in the default annuity form applicable to the Tier 1 Participant under the Qualified Plan.

(d) Make-Up Benefit. Except as provided in (f) and (g), benefits shall be paid to a Tier 2 Participant in one of the standard or optional annuity forms of benefit described in 6.01 and 6.02 of the Qualified Plan, other than a joint and survivor annuity upon marriage or remarriage after the annuity starting date, as selected by the Tier 2 Participant in accordance with the rules of the Qualified Plan, commencing upon a Separation from Service as follows:

(i) If the Tier 2 Participant is eligible to receive normal retirement benefits under the Qualified Plan based on having reached age 62 at the time of Separation from Service, and therefore receives an amount of benefits under this Plan calculated consistently therewith, the annuity shall commence with the first month following the Separation from Service.

(ii) If the Tier 2 Participant is eligible to receive early retirement benefits under the Qualified Plan based on having satisfied the Rule of 70 at the time of Separation from Service, and therefore receives an amount of benefits under this Plan calculated consistently therewith, the annuity shall commence with the first month following the later of the Tier 2 Participant's 55th birthday or the Tier 2 Participant's Separation from Service.

(iii) If the Tier 2 Participant is eligible to receive disability retirement benefits under the Qualified Plan, and therefore receives an amount of benefits under this Plan calculated consistently therewith, the annuity shall commence with the first month following the later of the Tier 2 Participant's 55th birthday or the Tier 2 Participant's Separation from Service.

(iv) If the Tier 2 Participant is not eligible to receive normal retirement benefits, early retirement benefits or disability retirement benefits under the Qualified Plan, but is eligible to receive termination benefits under this Plan, the annuity shall commence with the first month following the Tier 2 Participant's 62nd birthday.

(v) If the Tier 2 Participant's surviving spouse is eligible to receive death benefits under the Qualified Plan as a result of the Tier 2 Participant's death before commencement of benefits under this Plan, the annuity shall commence in the month that benefits would have commenced as provided in this 7(d) if the Tier 2 Participant had a Separation from Service on the date of death (or on the Tier 2 Participant's actual Separation from Service, if earlier) and then survived until benefits had commenced.

(vi) If the Tier 2 Participant elects a form of annuity benefit under the Qualified Plan at least 30 days prior to the first day of the month in which the benefit under this 7(d) is required to commence, the annuity benefit shall be paid in the same annuity form as selected under the Qualified Plan. If the Tier 2 Participant does not make a timely election under this 7(d), the annuity benefit shall be paid in the default annuity form applicable to the Tier 2 Participant under the Qualified Plan.

(e) Actuarial Equivalency. The amount payable in any of the annuity forms provided in (b) shall be the actuarial equivalent of the lump sum in (a), or of the amount described in 4(f), 5(d), or 6(d), based on the actuarial assumptions used for determining equivalent benefits under the Qualified Plan at the time of the Participant's commencement of benefits.

(f) 6-Month Delay for Specified Employees. For a Participant who is a key employee as defined in Section 416(i) of the Internal Revenue Code for the plan year of Separation from Service, payment of a lump sum or commencement of monthly annuity benefits shall be postponed until the first day of the seventh calendar month following the Participant's Separation from Service. All amounts due before the first day of the seventh calendar month shall be paid to the Participant as soon as practicable after that day together with interest from the date each payment otherwise would have been payable until the date actually paid. Interest for any period will be paid at the same rate applicable for that period under Section 6(f) of the Company's Deferred Compensation Plan for Directors and Executives.

(g) Small Benefit Cash Out. If the actuarial equivalent lump sum present value of a Tier 2 Participant's benefits, based on the actuarial assumptions used for determining equivalent benefits under the Qualified Plan at the time of the Participant's commencement of benefits, is no more than the applicable dollar amount under Internal Revenue Code section 402(g)(1)(B) (which is $15,500 in 2007 and 2008), the benefit shall be paid as a lump sum in such amount at the time annuity payments would have otherwise commenced under 7(d).

8. Death Benefit.

(a) Beneficiary. If a Tier 1 Participant dies before Separation from Service, a death benefit shall be paid to the Beneficiary designated by the Tier 1 Participant on a written form prescribed by the Committee. A designation made by the Tier 1 Participant shall remain in effect until changed by a subsequent designation. If no Beneficiary has been designated or no person designated by the Tier 1 Participant survives, the Beneficiary shall be the following in order of priority:

(i) The Participant's surviving spouse.

(ii) The Participant's surviving children in equal shares.

(iii) The Participant's estate.

(b) Amount of Benefit. The death benefit shall have a lump sum value equal to 50 percent of the amount determined under the formula in 4 (b) for the benefit at Normal Retirement Date, calculated on the basis of the Tier 1 Participant's Final Average Pay, Years of Participation, and Pension Offset determined as of the day before death.

(c) Form of Payment. The amount calculated under (b) shall be converted to an actuarial equivalent single life annuity for the life of the Beneficiary commencing on the first of the month following the date of death, except as follows. If the lump sum value is no more than the applicable dollar amount under Internal Revenue Code section 402(g)(1)(B) (which is $15,500 in 2007 and 2008), the lump sum shall be paid to the Beneficiary within 30 days after the date of death in lieu of a life annuity. Actuarial equivalency shall be based on the actuarial assumptions used for determining equivalent benefits under the Qualified Plan at the time of the Tier 1 Participant’s death.

(d) Make-Up Benefit. If a Tier 2 Participant dies with a surviving spouse entitled to a death benefit under the Qualified Plan, a death benefit shall be payable to the surviving spouse commencing at the date determined under 7(d) equal to the amount, if any, by which the Qualified Plan death benefit would be greater than the actual death benefit calculated as of that date under the Qualified Plan in the absence of the limits in 4(f)(i) and (ii) and based on deferred salary and bonus as provided in 4(g).

9. Change in Control.

(a) Enhancements. Each Participant who becomes entitled to a Change in Control Severance Benefit shall be provided enhanced benefits as follows:

(i) All Participants shall be fully vested in benefits under the Plan, regardless of Years of Participation.

(ii) Tier 1 Participants shall be credited with three additional Years of Participation beyond those the Participant has actually completed.

(iii) The make-up benefit provided for Tier 2 Participants under 4(f), 5(d), 6(d), 7(d), and 8(d) shall be calculated by subtracting the Tier 2 Participant’s Qualified Plan benefit calculated as of the applicable benefit commencement date under 7(d) from a Qualified Plan benefit that is calculated as of the same date without the limits described in 4(f)(i) and (ii), that counts deferred salary and bonus as provided in 4(g), and that is based on the Tier 2 Participant’s actual years of service credited for benefits under the Qualified Plan plus three additional years.

(b) Change in Control Severance Benefit. "Change in Control Severance Benefit" means, for any Participant who is party to a Change in Control Severance Agreement with the Company, the severance benefit provided for in such agreement; provided, however, that such severance benefit is a "Change in Control Severance Benefit" for purposes of the Plan only if, under the terms of the Participant’s Change in Control Severance Agreement, the Participant becomes entitled to the severance benefit (i) after a change in control of the Company has occurred, (ii) because the Participant’s employment with the Company has been terminated by the Participant for good reason in accordance with the terms and conditions of the Change in Control Severance Agreement or by the Company other than for cause or disability, and (iii) because the Participant has satisfied any other conditions or requirements specified in the Change in Control Severance Agreement and necessary for the Participant to become entitled to receive the severance benefit. Under no circumstances will a Participant who is not party to a Change in Control Severance Agreement be deemed to become entitled to a Change in Control Severance Benefit for purposes of the Plan. For purposes of this Section 9(b), the terms "change in control," "good reason," "cause" and "disability" shall have the meanings as may be set forth in the Participant’s Change in Control Severance Agreement, if any.

(c) Possible Benefit Recalculation. With respect to any Participant who is party to a Change in Control Severance Agreement, it may be the case that (i) the Participant’s employment with the Company is terminated prior to a "change in control" of the Company (as defined in the Participant’s Change in Control Severance Agreement), (ii) a change in control of the Company occurs after such termination, and (iii) the Participant then becomes entitled to a Change in Control Severance Benefit. If, after such termination of employment and prior to the time that the Participant becomes entitled to a Change in Control Severance Benefit, benefit payments to the Participant have started under the Plan, then, at such time thereafter as the Participant becomes entitled to a Change in Control Severance Benefit, the benefits payable to the Participant under the Plan shall be retroactively recalculated to reflect the enhancements described in Section 9(a). To the extent that the amount of the benefit payments paid to the Participant prior to such recalculation is less than the amount of such payments as so recalculated, the difference will be paid to the Participant in a cash lump sum (without interest) as soon as practicable after the change in control of the Company.

10. Administration.

(a) Committee Duties. This Plan shall be administered by the Organization and Executive Compensation Committee of the Board (the "Committee"). The Committee shall have responsibility for the general administration of the Plan and for carrying out its intent and provisions. The Committee shall interpret the Plan and have such powers and duties as may be necessary to discharge its responsibilities. The Committee may, from time to time, employ other agents and delegate to them such administrative duties as it sees fit, and may from time to time consult with counsel who may be counsel to the Company.

(b) Binding Effect of Decisions. The decision or action of the Committee in respect of any question arising out of or in connection with the administration, interpretation and application of the Plan and the rules and regulations promulgated hereunder shall be final and conclusive and binding upon all persons having any interest in the Plan.

11. Claims Procedure.

(a) Claim. Any person claiming a benefit, requesting an interpretation or ruling under the Plan, or requesting information under the Plan shall present the request in writing to the Committee, which shall respond in writing as soon as practicable.

(b) Denial of Claim. If the claim or request is denied, the written notice of denial shall state:

(i) The reasons for denial, with specific reference to the Plan provisions on which the denial is based;

(ii) A description of any additional material or information required and an explanation of why it is necessary; and

(iii) An explanation of the Plan's claim review procedure.

(c) Review of Claim. Any person whose claim or request is denied or who has not received a response within 30 days may request review by notice given in writing to the Committee. The claim or request shall be reviewed by the Committee who may, but shall not be required to, grant the claimant a hearing. On review, the claimant may have representation, examine pertinent documents, and submit issues and comments in writing.

(d) Final Decision. The decision on review shall normally be made within 60 days. If an extension of time is required for a hearing or other special circumstances, the claimant shall be notified and the time limit shall be 120 days. The decision shall be in writing and shall state the reasons and the relevant Plan provisions. All decisions on review shall be final and bind all parties concerned.

12. Amendment and Termination of the Plan.

(a) Amendment. The Board may at any time amend the Plan in whole or in part; provided, however, that no amendment shall without the consent of each affected Participant (i) decrease the Participant's benefit accrued under 4 as of the date of amendment, or (ii) accelerate the payment of benefits under the Plan. The Board shall have the right to apply an amendment retroactively, including any amendment necessary to comply with restrictions on nonqualified deferred compensation provided by Section 409A of the Internal Revenue Code.

(b) Partial Termination. The Board may at any time partially terminate the Plan if, in its judgment, the tax, accounting, or other effects of the continuance of the Plan, or potential payments thereunder, would not be in the best interests of the Company. Upon partial termination, no further benefits shall accrue under the Plan, which shall continue for the purpose of paying benefits accrued under the Plan as of the partial termination date as they become payable.

(c) Complete Termination. The Board may completely terminate the Plan, provided such termination is covered by an exception (set forth in regulations or other guidance of the Internal Revenue Service) to the prohibition on acceleration of deferred compensation. In that event, on the effective date of the complete termination, the Plan shall cease to operate and the Company shall determine the lump sum present value of each Participant's benefit rights under the Plan as of the close of business on such effective date. The Company shall pay out such present value to the Participant in a single lump sum as soon as practicable after such effective date.

13. Miscellaneous.

(a) Unsecured General Creditor. Participants and their beneficiaries, heirs, successors and assigns shall have no legal or equitable rights, interest or claims in any property or assets of the Company, nor shall they be beneficiaries of, or have any rights, claims or interests in any mutual funds, other investment products or the proceeds therefrom owned or which may be acquired by the Company. Except as provided in (b), any and all of the Company's assets shall be, and remain, the general, unpledged, unrestricted assets of the Company. The Company's obligation under the Plan shall be that of an unfunded and unsecured promise to pay money in the future, and the rights of Participants and beneficiaries shall be no greater than those of unsecured general creditors of the Company.

(b) Trust Fund. The Company shall be responsible for the payment of all benefits provided under the Plan. The Company shall establish one or more trusts, with such trustees as the Board may approve, for the purpose of providing for the payment of such benefits, but the Company shall have no obligation to contribute to such trusts except as specifically provided in the applicable trust documents. Such trust or trusts shall be irrevocable, but the assets thereof shall be subject to the claims of the Company's creditors. To the extent any benefits provided under the Plan are actually paid from any such trust, the Company shall have no further obligation with respect thereto, but to the extent not so paid, such benefits shall remain the obligation of, and shall be paid by, the Company.

(c) Non-assignability. Neither a Participant nor any other person shall have the right to commute, sell, assign, transfer, pledge, anticipate, mortgage or otherwise encumber, transfer, hypothecate or convey in advance of actual receipt the amounts, if any, payable hereunder, or any part thereof, which are, and all rights to which are, expressly declared to be non-assignable and nontransferable. No part of the amounts payable shall, prior to actual payment, be subject to seizure or sequestration for the payment of any debts, judgments, alimony or separate maintenance owed by a Participant or any other person, nor be transferable by operation of law in the event of a Participant's or any other person's bankruptcy or insolvency.

(d) Not a Contract of Employment. The terms and conditions of this Plan shall not be deemed to constitute a contract of employment between the Company and any Participant, and the Participants (and their Beneficiaries) shall have no rights against the Company except as may otherwise be specifically provided herein. Moreover, nothing in this Plan shall be deemed to give a Participant the right to be retained in the service of the Company or to interfere with the right of the Company to discipline or discharge the Participant at any time.

(e) Withholding; Payroll Taxes. The Company shall withhold from payments made hereunder any taxes required to be withheld from such payments under federal, state or local law. When the value of a Participant's benefits under the Plan becomes subject to FICA tax, as determined by applicable law, the Participant's share of FICA shall be withheld from other non-deferred compensation payable to the Participant. Any amount not covered by such withholding shall be paid by the Participant to the Company out of other funds.

(f) Payment to Guardian. If a benefit under the Plan is payable to a minor or a person declared incompetent or to a person incapable of handling the disposition of his property, the Committee may direct payment of such Plan benefit to the guardian, legal representative or person responsible for the care and custody of such minor, incompetent or person. The Committee may require proof of incompetence, minority, incapacity or guardianship as it may deem appropriate prior to distribution of the Plan benefit. Such distribution shall completely discharge the Committee and the Company from all liability with respect to such benefit.

(g) Governing Law. The provisions of this Plan shall be construed and interpreted according to the laws of the State of Oregon, except as preempted by federal law.

(h) Validity. In case any provision of this Plan shall be held illegal or invalid for any reason, said illegality or invalidity shall not affect the remaining parts hereof, but this Plan shall be construed and enforced as if such illegal and invalid provisions had never been inserted herein.

(i) Notice. Any notice or filing required or permitted to be given to the Company or the Committee under the Plan shall be sufficient if in writing and hand delivered, or sent by registered or certified mail, to the Secretary of the Company. Such notice shall be deemed given as of the date of delivery or, if delivery is made by mail, as of the date shown on the postmark on the receipt for registration or certification.

(j) Successors. The provisions of this Plan shall bind and inure to the benefit of the Company and its successors and assigns. The term successors as used herein shall include any corporate or other business entity which shall, whether by merger, consolidation, purchase or otherwise acquire all or substantially all of the business and assets of the Company, and successors of any such corporation or other business entity.

The foregoing 2007 Restatement was approved by the Board of Directors of Northwest Natural Gas Company on December 20, 2007.

NORTHWEST NATURAL GAS COMPANY

By: /s/ Mark S. Dodson

Attest:________________________________

Section 12: EX-10.E (EXECUTIVE DEFERRED COMPENSATION PLAN, EFFECTIVE AS OF JANUARY 1, 1987)

Exhibit 10e.

NORTHWEST NATURAL GAS COMPANY

EXECUTIVE DEFERRED COMPENSATION PLAN

2008 RESTATEMENT

Effective January 1, 1987

Restated as of February 28, 2008

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NORTHWEST NATURAL GAS COMPANY

EXECUTIVE DEFERRED COMPENSATION PLAN

Effective as of January 1, 1987

Restated as of February 28, 2008

ARTICLE I

PURPOSE

1.1 Restatement. Northwest Natural Gas Company adopted an Executive Deferred Compensation Plan (the "Plan") effective January 1, 1987, which was previously restated effective as of January 1, 2001, January 1, 2003, December 15, 2005 and January 1, 2007. The Plan was partially terminated in accordance with Paragraph 9(b)(i) effective December 31, 2004, so deferrals of compensation are no longer being made under the Plan. The Plan is now amended and restated by this 2008 Restatement, effective as of February 28, 2008.

1.2 Purpose. The purpose of this Executive Deferred Compensation Plan is to provide an unfunded deferred compensation plan for a select group of top management personnel.

ARTICLE II

DEFINITIONS

For purposes of this Plan, the following words and phrases shall have the meanings indicated, unless the context clearly indicates otherwise:

2.1 Account. "Account" means the record or records maintained by the Corporation for each Executive in accordance with Article IV with respect to any deferral of Compensation pursuant to this Plan. An Account shall be either a "Stock Account" as described in Section 4.3 or a "Cash Account" as described in Section 4.4.

2.2 Acquiror Stock. "Acquiror Stock" is defined in Section 4.5.

2.3 Base Annual Salary. "Base Annual Salary" means the annual compensation payable to an Executive, excluding bonuses, commissions, LTIP Compensation and other noncash compensation.

2.4 Beneficiary. "Beneficiary" means the person, persons or entity designated under Article VI to receive any Plan Benefits payable after an Executive's death.

2.5 Board. "Board" means the Board of Directors of Northwest Natural Gas Company or any successor thereto.

2.6 Bonus. "Bonus" means the compensation derived under the Corporation’s Executive Annual Incentive Plan or other similar incentive plan and payable in any year in a lump sum to an Executive.

2.7 Cash Compensation. "Cash Compensation" means the total Base Annual Salary and Bonus remuneration payable by the Corporation to the Executive for services.

2.8 Change in Control. "Change in Control" means the occurrence of any of the following events:

(a) The consummation of:

(i) any consolidation, merger or plan of share exchange involving the Corporation (a "Merger") as a result of which the holders of outstanding securities of the Corporation ordinarily having the right to vote for the election of directors ("Voting Securities") immediately prior to the Merger do not continue to hold at least 50% of the combined voting power of the outstanding Voting Securities of the surviving corporation or a parent corporation of the surviving corporation immediately after the Merger, disregarding any Voting Securities issued to or retained by such holders in respect of securities of any other party to the Merger; or

(ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of the Corporation;

(b) At any time during a period of two consecutive years, individuals who at the beginning of such period constituted the board of directors of the Corporation ("Incumbent Directors") shall cease for any reason to constitute at least a majority thereof; provided, however, that the term "Incumbent Director" shall also include each new director elected during such two-year period whose nomination or election was approved by two-thirds of the Incumbent Directors then in office; or

(c) Any person (as such term is used in Section 14(d) of the Securities Exchange Act of 1934, other than the Corporation or any employee benefit plan sponsored by the Corporation) shall, as a result of a tender or exchange offer, open market purchases or privately negotiated purchases from anyone other than the Corporation, have become the beneficial owner (within the meaning of Rule 13d-3 under the Securities Exchange Act of 1934), directly or indirectly, of Voting Securities representing twenty percent (20%) or more of the combined voting power of the then outstanding Voting Securities.

2.9 Committee. "Committee" means the Organization and Executive Compensation Committee, or such other Committee as may be designated by the Board.

2.10 Common Stock. "Common Stock" means common stock of the Corporation.

2.11 Compensation. "Compensation" means Cash Compensation and LTIP Compensation.

2.12 Corporate Transaction. "Corporate Transaction" means any of the following:

(a) any consolidation, merger or plan of share exchange involving the Corporation pursuant to which shares of Common Stock would be converted into cash, securities or other property; or

(b) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of the Corporation.

2.13 Corporation. "Corporation" means Northwest Natural Gas Company, an Oregon corporation, or any successor thereto, and any corporations or other entities affiliated with or subsidiary to it that may be selected by the Board from time to time and which take action to adopt and implement this Plan.

2.14 Deferral Commitment. "Deferral Commitment" means a Deferral Commitment made by an Executive pursuant to Article III and for which a Participation Agreement has been submitted by the Executive to the Committee.

2.15 Deferral Deadline. "Deferral Deadline" means, for any Compensation payable to an Executive, the last day on which the Executive can submit a Participation Agreement to make a Deferral Commitment with respect to such Compensation. The Deferral Deadlines for various forms of Compensation shall be as follows:

(a) For Base Annual Salary payable in any calendar year, the Deferral Deadline shall be the last day of the previous calendar year; provided, however, that for a person who becomes an eligible Executive during a year, the Deferral Deadline for Base Annual Salary payable for the remainder of the year shall be 30 days after the person becomes an Executive and the Deferral Commitment shall only apply to Base Annual Salary payable after the Participation Agreement is submitted.

(b) For Bonus payable in any calendar year, including Bonus payable with respect to the Executive’s or the Corporation’s performance in the previous calendar year, the Deferral Deadline shall be the last day of the previous calendar year.

(c) For LTIP Compensation payable at any time, the Deferral Deadline shall be the date one year prior to the vesting date for time-based awards and the date one year prior to the last day of the award period for performance-based awards; provided, however, that the Deferral Deadline for any LTIP Compensation that becomes payable in any calendar year on an accelerated basis as a result of a Change in Control shall be the last day of the previous calendar year.

2.16 Deferred Cash Compensation. "Deferred Cash Compensation" means the amount of Cash Compensation that the Executive elects to defer pursuant to a Deferral Commitment.

2.17 Deferred Compensation Account Benefit. "Deferred Compensation Account Benefit" means the benefit payable to an Executive as calculated pursuant to Article IV and payable under Sections 5.1 through 5.6.

2.18 Determination Date. "Determination Date" means the last day of each calendar quarter.

2.19 Disability. "Disability" means a physical or mental condition that, in the opinion of the Committee, prevents the Executive from satisfactorily performing the Executive's usual duties for the Corporation. The Committee's decision as to Disability will be based upon medical reports and/or other evidence satisfactory to the Committee.

2.20 Executive. "Executive" means one of a select group of management or highly compensated employees of the Corporation, which shall consist of all executive officers of the Corporation and any other employee of the Corporation designated in writing by the Chief Executive Officer of the Corporation for participation in the benefits of the Plan.

2.21 Financial Hardship. "Financial Hardship" means a severe financial hardship to the Executive resulting from a sudden and unexpected illness or accident of the Executive or of a dependent of the Executive, loss of the Executive's property due to casualty, or other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Executive. Financial Hardship shall be determined by the Committee on the basis of information supplied by the Executive in accordance with uniform guidelines promulgated from time to time by the Committee.

2.22 Interest. "Interest" is credited to Cash Accounts under the Plan and means the quarterly equivalent of an annual yield that is two percentage points (2%) higher than the annual yield on Moody's Average Corporate Bond Yield for the preceding quarter, as published by Moody's Investors Service, Inc. (or any successor thereto), or, if such index is no longer published, a substantially similar index selected by the Board. At no time shall such Interest rate be less than six percent (6%) annually.

Notwithstanding the foregoing provisions of this Section 2.22, effective as of January 1, 2017, the Interest rate shall equal the rate of interest for interest credited to cash accounts under the Corporation's Deferred Compensation Plan for Directors and Executives, as such plan may be amended from time to time (the "DCPDE"), regardless of whether or not such rate of interest shall be more or less than six percent (6%) annually; provided, however, that if at any time on or after January 1, 2017 there is no interest credited to cash accounts under the DCPDE because the DCPDE shall have ceased to operate or for any other reason, then, at such time on or after January 1, 2017, the Interest rate shall equal the quarterly equivalent of an annual yield that is equal to the annual yield on Moody's Average Corporate Bond Yield for the preceding quarter, as published by Moody's Investors Service, Inc. (or any successor thereto), or, if such index is no longer published, a substantially similar index selected by the Board, regardless of whether or not such Interest rate shall be more or less than six percent (6%) annually. Any change in the Interest rate that occurs on January 1, 2017 or thereafter pursuant to the provisions of this paragraph shall not constitute a "change in the definition of Interest" within the meaning of Section 9.1(b) below.

2.23 LTIP Compensation. "LTIP Compensation" means compensation paid to an Executive pursuant to an award under the Corporation's Long Term Incentive Plan. LTIP Compensation may be payable to the Executive either in Common Stock ("Stock LTIP Compensation") or in cash ("Cash LTIP Compensation").

2.24 Matching Contribution. "Matching Contribution" means the contribution made by the Corporation and credited to the Executive's Account under Section 4.2.

2.25 Participation Agreement. "Participation Agreement" means the agreement submitted by an Executive to the Committee no later than the applicable Deferral Deadline with respect to one or more Deferral Commitments.

2.26 Plan Benefits. "Plan Benefits" mean the Deferred Compensation Account Benefit and the Supplemental Retirement Benefit.

2.27 Retirement. "Retirement" means either early retirement, normal retirement, or disability retirement under the Retirement Plan.

2.28 Retirement Plan. "Retirement Plan" means the Corporation's Retirement Plan for Non-Bargaining Unit Employees.

2.29 Supplemental Retirement Benefit. "Supplemental Retirement Benefit" means the benefit payable to an Executive under Section 5.7.

2.30 Trust. "Trust" means the Northwest Natural Gas Company Umbrella Trust™ For Executives established by the Corporation in connection with this Plan.

ARTICLE III

DEFERRAL COMMITMENTS

3.1 Participation. An eligible Executive may elect to participate in the Plan by submitting a Participation Agreement to the Committee no later than the applicable Deferral Deadline. An election to defer Compensation by the Executive shall continue from year to year and shall be irrevocable with respect to Compensation once the Deferral Deadline for that Compensation has passed, but may be modified or terminated by written notice from the Executive at any time on or prior to the Deferral Deadline for that Compensation.

3.2 Deferral Election.

(a) Election to Defer Cash Compensation. An Executive may, no later than the applicable Deferral Deadline, elect to defer receipt of a certain whole percentage, up to fifty percent (50%), of the Base Annual Salary and a certain whole percentage, up to one hundred percent (100%), of any Bonus payable to the Executive as an employee of the Corporation.

(b) Election to Defer LTIP Compensation. An Executive may, no later than the applicable Deferral Deadline, elect to defer receipt of a certain whole percentage, up to one hundred percent (100%), of any Stock LTIP Compensation and a certain whole percentage, up to one hundred percent (100%), of any Cash LTIP Compensation that becomes payable to the Executive.

(c) FICA Withholding. Under current law, all Compensation and Matching Contributions credited to an Executive's Accounts will be treated as wages subject to FICA tax, and the Corporation will be required to withhold FICA tax from the Executive. The amount required to be withheld for FICA tax with respect to any amount of deferred Compensation or related Matching Contribution shall be withheld from the non-deferred portion, if any, of the same Compensation; provided, however, that if the non-deferred portion of the Compensation is insufficient to cover the full required withholding, the Corporation shall withhold the remaining amount from other non-deferred Compensation payable to the Executive unless the Executive otherwise pays such remaining amount to the Corporation.

(d) Financial Hardship. Termination of the Executive's election to defer may, solely in the Committee's discretion, become applicable as soon as practicable after the Committee's determination that the Executive has incurred Financial Hardship, as evidenced by the Executive to the Committee.

ARTICLE IV

DEFERRED COMPENSATION ACCOUNTS

4.1 Accounts. The Corporation shall establish on its books one or two separate Accounts for each Executive who elects to defer Compensation under the Plan: a Cash Account and/or a Stock Account. Compensation deferred by an Executive shall be credited to the Stock Account or the Cash Account as elected by the Executive at the time the Executive elects to defer Compensation. Such election may be divided between the two Accounts in increments of twenty-five percent (25%) of the deferred Compensation covered by the election. An Executive may change the allocation of new deferrals of Compensation between the Stock Account and the Cash Account, but such change shall apply to new deferrals only if it is submitted on or prior to the Deferral Deadline for such new deferrals. Once Compensation has been credited to the Stock Account or the Cash Account, no transfers between the Stock Account and the Cash Account shall be permitted except as otherwise provided in Section 4.5(d). The credit for deferred Compensation shall be entered on the Corporation's books of account at the time that Compensation not deferred is paid or payable to the Executive.

4.2 Matching Contribution. The Corporation shall credit a Matching Contribution to an Executive's Account based on the amount of Deferred Cash Compensation elected by the Executive; provided, however, that no Matching Contributions shall be made to the Account of any Executive who is not eligible to participate in the Corporation's Retirement K Savings Plan until such time of eligibility. The amount of the Matching Contribution shall be equal to the excess of (a) the lesser of (i) sixty percent (60%) of the Executive's Deferred Cash Compensation during the calendar year, or (ii) three and six-tenths percent (3.6%) of the Executive's Cash Compensation during such calendar year, over (b) the amount, if any, the Corporation has contributed for such calendar year as a matching contribution for the Executive to the Retirement K Savings Plan. Matching Contributions shall be credited to the Executive's Account on the last day of the calendar year in which the Matching Contribution was earned, and shall be allocated between the Executive's Cash Account and Stock Account in the same ratio as Deferred Cash Compensation is allocated for the year.

4.3 Stock Account. An Executive's Stock Account shall be denominated in shares of Common Stock, including fractional shares. With respect to Stock LTIP Compensation deferred to an Executive's Stock Account, the number of deferred shares shall be credited to the Stock Account. With respect to each amount of Cash Compensation, Cash LTIP Compensation or Matching Contribution deferred to an Executive's Stock Account, the amount of cash deferred shall be divided by the closing market price of the Common Stock reported for the last trading day preceding the date on which the Stock Account is to be credited, and the resulting number of shares (including fractional shares) shall be credited to the Executive's Stock Account. As of each date for payment of dividends on the Common Stock, the Stock Accounts shall be credited with an additional number of shares (including fractional shares) equal to the amount of dividends that would be paid on the number of shares recorded as the balance of the Stock Account as of the record date for such dividend divided by closing market price of the Common Stock reported for such payment date or, if such day is not a trading day, the next trading day.

4.4 Cash Account. An Executive's Cash Account shall be denominated in dollars. With respect to each amount of Cash Compensation, Cash LTIP Compensation or Matching Contribution deferred to an Executive's Cash Account, an equal amount of dollars shall be credited to the Executive's Cash Account. With respect to Stock LTIP Compensation deferred to an Executive's Cash Account, the number of deferred shares shall be multiplied by the closing market price of the Common Stock reported for the last trading day preceding the date on which the Cash Account is to be credited, and the resulting number of dollars shall be credited to the Executive's Cash Account. Interest on each Cash Account shall be calculated as of each Determination Date based upon the average daily balance of the Cash Account since the preceding Determination Date and shall be credited to the Cash Account at that time.

4.5 Effect of Corporate Transaction on Stock Accounts. At the time of consummation of a Corporate Transaction, if any, the amount credited to an Executive's Stock Account shall be converted into a credit for cash or common stock of the acquiring company ("Acquiror Stock") based on the consideration received by shareholders of the Corporation in the Corporate Transaction, as follows:

(a) Stock Transaction. If holders of Common Stock receive Acquiror Stock in the Corporate Transaction, then (i) the amount credited to each Executive's Stock Account shall be converted into a credit for the number of shares of Acquiror Stock that the Executive would have received as a result of the Corporate Transaction if the Executive had actually held the Common Stock credited to his or her Stock Account immediately prior to the consummation of the Corporate Transaction, and (ii) Stock Accounts will thereafter be denominated in shares of Acquiror Stock and ongoing deferrals of Compensation shall continue to be made in accordance with outstanding Deferral Commitments into the Stock Accounts as so denominated.

(b) Cash or Other Property Transaction. If holders of Common Stock receive cash or other property in the Corporate Transaction, then (i) the amount credited to an Executive's Stock Account shall be transferred to the Executive's Cash Account and converted into a cash credit for the amount of cash or the value of the property that the Executive would have received as a result of the Corporate Transaction if the Executive had actually held the Common Stock credited to his or her Stock Account immediately prior to the consummation of the Corporate Transaction, and (ii) Stock Accounts shall no longer exist under the Plan and all ongoing deferrals shall thereafter be made into Cash Accounts.

(c) Combination Transaction. If holders of Common Stock receive Acquiror Stock and cash or other property in the Corporate Transaction, then (i) the amount credited to each Executive's Stock Account shall be converted in part into a credit for Acquiror Stock under Section 4.5(a) and in part into a credit for cash under Section 4.5(b) in the same proportion as such consideration is received by shareholders, and (ii) ongoing deferrals into Stock Accounts pursuant to outstanding Deferral Commitments shall continue to be made into Stock Accounts in accordance with Section 4.5(a).

(d) Election Following Stock Transaction. For a period of 12 months following the consummation of any Corporate Transaction which results in Executives having Stock Accounts denominated in Acquiror Stock, each Executive shall have a one-time right to elect to transfer the entire amount in the Executive's Stock Account into the Executive's Cash Account; provided, however, that this election shall not be available if the Corporate Transaction results in holders of Common Stock becoming holders of all of the outstanding common stock of a parent corporation of the Corporation. Such election shall be made by written notice to the Corporation and shall be effective on the date received by the Corporation. If such an election is made, the amount of cash to be credited to the Executive's Cash Account shall be determined by multiplying the number of shares of Acquiror Stock in the Executive's Stock Account by the closing market price of the Acquiror Stock reported for the last trading day preceding the effective date of the election.

4.6 Statement of Account. As soon as practicable after each Determination Date, a report shall be issued by the Corporation to each participating Executive setting forth the balances of the Executive's Accounts under the Plan as of the immediately preceding Determination Date.

ARTICLE V

PLAN BENEFITS

5.1 Plan Benefit. The Corporation shall pay Plan Benefits to each Executive pursuant to this Article V equal to the Executive's Accounts.

5.2 Commencement of Payments.

(a) Payment of any Deferred Compensation Account Benefits under the Plan shall commence as of the earlier of:

(i) A date elected by the Executive as specified in the applicable Participation Agreement between the Corporation and the Executive; or

(ii) The first business day of January following the year of the Executive's Retirement, total Disability or other termination of employment.

(b) Supplemental Retirement Benefits under Section 5.7 shall be made as of, or commence as of, the earliest date for which a monthly payment is payable to or for the Executive under the Retirement Plan.

5.3 Lump Sum or Installment Payments.

(a) At the time the Executive elects to defer Compensation, the Executive may also elect to receive Deferred Compensation Account Benefits either:

(i) In equal or approximately equal annual installments (the number of such installments not to exceed fifteen (15)) as designated by the Executive, with the amount of the installments being adjusted over the installment period to reflect changes in Interest or dividends credited to the Executive's Accounts;

(ii) In a single sum payment; or

(iii) In a combination of partial lump sum payment, and remainder in installments.

(b) An Executive may elect to modify such election by filing a change of payment designation which shall supersede the prior form of payment designation in the Participation Agreement for Compensation deferred in any one (1) or more calendar years. If the Executive's most recent change of payment designation has not been filed one (1) full calendar year prior to the year of Executive's Retirement, Disability, other termination of employment or earlier date selected for commencement of payments, the prior election shall be used to determine the form of payment. For example, an Executive retiring in 2003 must file a written request with the Committee by December 31, 2001 to change the Executive's form of payment designation.

5.4 Form of Benefit Payment. Benefits payable to an Executive from a Stock Account shall only be paid to such Executive as a distribution of Common Stock (or Acquiror Stock, if applicable) plus cash for fractional shares. Benefits payable to an Executive from a Cash Account shall only be paid to such Executive in cash.

5.5 Hardship Distributions. Notwithstanding the foregoing provisions of this Article V, payment from the Executive's Accounts may be made to the Executive in the sole discretion of the Committee based upon a finding that an Executive has suffered a Financial Hardship. The amount of such a withdrawal shall be limited to the amount reasonably necessary to meet the Executive's needs resulting from the Financial Hardship. If payment is made due to Financial Hardship under this Plan, the Executive's deferrals shall cease for a twelve (12) month period. Any resumption of the Executive's deferrals under the Plan after such twelve (12) month period shall be made only at the election of the Executive in accordance with Article III herein.

5.6 Death Benefit. Upon the death of the Executive or a former Executive prior to the receipt of the full amount of Deferred Compensation Account Benefits, the balance of such benefits shall be paid by the Corporation to the applicable surviving designated Beneficiary or Beneficiaries as soon as practicable in the manner elected in writing by the Executive, or, if no such election is made, by single sum payment.

5.7 Supplemental Retirement Benefit. Any Executive who elects to defer Compensation under this Plan and who also satisfies the eligibility requirements for payment of any benefit under the Retirement Plan shall qualify for further payment by the Corporation of Supplemental Retirement Benefits payable as an annuity under this Plan, as provided below:

(a) Amount. The amount payable by the Corporation each month during the time an annuity benefit is payable to the Executive or Executive's Beneficiary(ies) under the Retirement Plan shall be:

(i) The amount that would be payable at such time under the Retirement Plan determined under Section 5.7(c) by treating all accrued benefits under the Retirement Plan as being payable only in the annuity form and by treating all Cash Compensation deferred by the Executive under this Plan as though it had been "paid" to or "received" by Executive in the year when the deferral was made, provided that all such deferred amounts shall be subject to the other applicable definitions and rules of the Retirement Plan relating to benefit determination; plus

(ii) The reduction, if any, in the amount of the "primary Social Security Benefit" which will actually be payable to the Executive, provided that such reduction results from the fact that Compensation deferred under this Plan causes the primary Social Security Benefit payable to the Executive to be reduced and that such reduction is not otherwise payable under Section 5.7(a)(i) above; minus

(iii) The amount actually payable at such time under the Retirement Plan as determined under Section 5.7(c) by treating all accrued benefits under the Retirement Plan as being payable only in the annuity form.

(b) Form and Duration. The form of Supplemental Retirement Benefit payable by the Corporation shall be the same annuity form, and shall be paid by the Corporation for the same duration, as the annuity benefit actually payable under the Retirement Plan. Such annuity benefit forms include (subject to any change in the Retirement Plan at the time payment begins) a standard life annuity (no survivorship benefit); a half (50%) or full (100%) joint and survivor annuity to the Executive and surviving spouse with or without a "pop-up" if the spouse dies before the Executive; a ten (10) year certain annuity which can provide death benefits to any surviving designated beneficiary; and a full (100%) joint and survivor benefit for the spouse of a vested married Executive who dies before retirement; and payees include the Executive and, if the operative form provides for payment after the Executive's death, the Executive's surviving spouse or other surviving designated Beneficiary(ies) or estate.

(c) Retirement Plan Lump Sum Election Ignored. Notwithstanding any election by an Executive to receive a portion of Executive's Retirement Plan benefit as a lump sum, the amount of the Supplemental Retirement Benefit as determined under Section 5.7(a) and the form and duration of the Supplemental Retirement Benefit as determined under Section 5.7(b) shall be calculated and determined as if Executive were to receive Executive's entire Retirement Plan accrued benefit in the same annuity form that applies to the annuity portion of Executive's Retirement Plan benefit.

5.8 Withholding; Payroll Taxes. The Corporation shall withhold from payments made hereunder any taxes required to be withheld from such payments under federal, state or local law. However, a Beneficiary may elect in writing not to have withholding for federal income tax purposes pursuant to Section 3405(a)(2) of the Internal Revenue Code, or any successor provision thereto.

5.9 Payment to Guardian. If a Plan Benefit is payable to a minor or a person declared incompetent or to a person incapable of handling the disposition of his or her property, the Committee may direct payment of such Plan Benefit to the guardian, legal representative or person having the care and custody of such minor, incompetent or person. The Committee may require proof of incompetence, minority, incapacity or guardianship as it may deem appropriate prior to distribution of the Plan Benefit. Such distribution shall completely discharge the Committee and the Corporation from all liability with respect to such benefit.

5.10 Accelerated Distribution. Notwithstanding any other provision of the Plan, an Executive shall be entitled to receive, upon written request to the Committee, a lump sum distribution equal to ninety percent (90%) of the balance in the Executive's Accounts as of the Determination Date immediately preceding the date on which the Committee receives the written request. The remaining balance shall be forfeited by the Executive. An Executive who receives a distribution under this section shall be suspended from participation in the Plan for twelve (12) months. The amount payable under this section shall be paid in a lump sum within sixty-five (65) days following the receipt of the notice by the Committee from the Executive.

ARTICLE VI

BENEFICIARY DESIGNATION

6.1 Beneficiary Designation. Each Executive shall have the right, at any time, to designate any person or persons as the Executive's Beneficiary or Beneficiaries (both primary as well as secondary) to whom benefits under this Plan shall be paid in the event of the Executive's death prior to complete distribution of the benefits due under the Plan. If greater than fifty percent (50%) of the benefit is designated to a Beneficiary other than the Executive's spouse, such Beneficiary designation shall be consented to by the Executive's spouse. Each Beneficiary designation shall be in written form prescribed by the Committee and will be effective only when filed with the Committee during the Executive's lifetime.

6.2 Amendments. Any Beneficiary designation may be changed by the Executive without the consent of any designated Beneficiary by the filing of a new Beneficiary designation with the Committee, subject to the spousal consent required in Section 6.1 above. The filing of a new Beneficiary designation form will cancel all Beneficiary designations previously filed.

6.3 No Beneficiary Designation. In the absence of an effective Beneficiary designation, or if all designated Beneficiaries predecease the Executive or die prior to complete distribution of the Executive's benefits, then the Executive's designated Beneficiary shall be deemed to be the Executive's estate.

6.4 Effect of Payment. The payment to the deemed Beneficiary shall completely discharge the Corporation's obligations under this Plan.

ARTICLE VII

ADMINISTRATION

7.1 Committee; Duties. This Plan shall be administered by the Committee. The Committee shall have such powers as may be necessary to discharge its responsibilities. These powers shall include, but not be limited to, interpretation of the Plan provisions, determination of amounts due to any Executive, the rights of any Executive or Beneficiary under this Plan, the right to require any necessary information from any Executive, determine the amounts credited to Executive's Accounts and Interest earned, and any other activities deemed necessary or helpful.

7.2 Agents. The Committee may, from time to time, employ other agents and delegate to them such administrative duties as it sees fit, and may from time to time consult with counsel who may be counsel to the Corporation.

7.3 Binding Effect of Decisions. The decision or action of the Committee with respect to any question arising out of or in connection with the administration, interpretation and application of the Plan and the rules and regulations promulgated hereunder shall be final and conclusive and binding upon all persons having any interest in the Plan.

7.4 Indemnity of Committee. To the extent permitted by applicable law, the Corporation shall indemnify, hold harmless and defend the members of the Committee against any and all claims, loss, damage, expense or liability arising from any action or failure to act with respect to this Plan, provided that the members of the Committee were acting in accordance with the applicable standard of care.

ARTICLE VIII

CLAIMS PROCEDURE

8.1 Claim. Any person claiming a benefit, requesting an interpretation or ruling under the Plan, or requesting information under the Plan shall present the request in writing to the Committee, which shall respond in writing as soon as practicable.

8.2 Denial of Claim. If the claim or request is denied, the written notice of denial shall state:

(a) The reasons for denial, with specific reference to the Plan provisions on which the denial is based;

(b) A description of any additional material or information required and an explanation of why it is necessary; and

(c) An explanation of the Plan's claim review procedure.

8.3 Review of Claim. Any person whose claim or request is denied or who has not received a response within thirty (30) days may request review by notice given in writing to the Committee. The claim or request shall be reviewed by the Committee who may, but shall not be required to, grant the claimant a hearing. On review, the claimant may have representation, examine pertinent documents, and submit issues and comments in writing.

8.4 Final Decision. The decision on review shall normally be made within sixty (60) days. If an extension of time is required for a hearing or other special circumstances, the claimant shall be notified and the time limit shall be one hundred twenty (120) days. The decision shall be in writing and shall state the reasons and the relevant Plan provisions. All decisions on review shall be final and bind all parties concerned.

ARTICLE IX

AMENDMENT AND TERMINATION OF THE PLAN

9.1 Amendment. The Board may at any time amend the Plan in whole or in part, subject to the following:

(a) Upon a Change in Control, no amendment shall be effective to change the payout schedule in Section 9.2(b).

(b) No amendment shall be effective to decrease or restrict the amount credited to any Account maintained under the Plan as of the date of the amendment. Changes in the definition of Interest shall be subject to the following restrictions:

(i) Notice. A change shall not become effective before the first day of the calendar year which follows the adoption of the amendment and at least thirty (30) days written notice of the amendment to the Executive.

(ii) Change in Control. Any change in the definition of Interest after a Change in Control shall apply only to those amounts credited to the Executive’s Account after the Change in Control.

9.2 Corporation’s Right to Terminate. The Board may at any time partially or completely terminate the Plan, if, in its judgment, the tax, accounting, or other effects of the continuance of the Plan, or potential payments thereunder, would not be in the best interests of the Corporation.

(a) Partial Termination. The Board may partially terminate the Plan by instructing the Committee not to accept any additional Deferral Commitments. In the event of such a partial termination, the Plan shall continue to operate and be effective with regard to Deferral Commitments entered into prior to the effective date of such partial termination.

(b) Complete Termination. The Board may completely terminate the Plan by instructing the Committee not to accept any additional Deferral Commitments, and terminating all ongoing Deferral Commitments. The Plan shall cease to operate and the Committee shall pay out to each Executive the balance in the Executive's Accounts in a lump sum or in equal annual installments amortized over the period listed in the payout schedule below based on the total balance in the Executive's Accounts at the time of such complete termination:

PAYOUT SCHEDULE

Total Balance of Accounts	Payout Period
Less than $10,000	Lump sum
$10,000 but less than $50,000	Lesser of 5 years or period elected in Participation Agreement
More than $50,000	Period elected in Participation Agreement

Interest earned on the unpaid balance in the Executive's Cash Account shall be the applicable Interest rate on the Determination Date immediately preceding the effective date of such complete termination.

ARTICLE X

MISCELLANEOUS

10.1 Unfunded Plan. This Plan is intended to be an unfunded plan maintained primarily to provide deferred compensation benefits for a select group of "management or highly-compensated employees" within the meaning of Sections 201, 301, and 401 of the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), and therefore to be exempt from the provisions of Parts 2, 3 and 4 of Title I of ERISA. Accordingly, the Plan shall terminate and no further benefits shall accrue hereunder in the event it is determined by a court of competent jurisdiction or by an opinion of counsel that the Plan constitutes an employee pension benefit plan within the meaning of Section 3(2) of ERISA which is not so exempt. In the event of a termination under this Section 10.1, all ongoing Deferral Commitments shall terminate, no additional Deferral Commitments will be accepted by the Committee, and the amount of each Executive's Account balance shall be distributed to such Executive at such time and in such manner as the Committee, in its sole discretion, determines.

10.2 Unsecured General Creditor. The Accounts shall be established solely for the purpose of measuring the amounts owed to Executives or their Beneficiaries under this Plan. Executives and their Beneficiaries, heirs, successors and assigns shall have no legal or equitable rights, interest or claims in any property or assets of the Corporation, nor shall they be Beneficiaries of, or have any rights, claims or interests in any life insurance policies, annuity contracts or the proceeds therefrom owned or which may be acquired by the Corporation. Except as may be provided in Section 10.3, such policies, annuity contracts or other assets of the Corporation shall not be held under any trust for the benefit of the Executives, their Beneficiaries, heirs, successors or assigns, or held in any way as collateral security for the fulfilling of the obligations of the Corporation under this Plan. Any and all of the Corporation's assets and policies shall be, and remain, the general, unpledged, unrestricted assets of the Corporation. The Corporation's obligation under the Plan shall be that of an unfunded and unsecured promise to pay money in the future.

10.3 Trust Fund. The Corporation shall be responsible for the payment of all benefits provided under the Plan. The Corporation shall establish the Trust, with such trustee or trustees as the Board may approve, for the purpose of providing for the payment of such benefits. The Trust shall be irrevocable, but the assets thereof shall be subject to the claims of the Corporation's creditors. To the extent any benefits provided under the Plan are actually paid from the Trust, the Corporation shall have no further obligation with respect thereto, but to the extent not so paid, such benefits shall remain the obligation of, and shall be paid by, the Corporation.

10.4 Nonassignability. Neither an Executive nor any other person shall have the right to commute, sell, assign, transfer, pledge, anticipate, mortgage or otherwise encumber, transfer, hypothecate or convey in advance of actual receipt the amounts, if any, payable hereunder, or any part thereof, which are, and all rights to which are, expressly declared to be unassignable and nontransferable. No part of the amounts payable shall, prior to actual payment, be subject to seizure or sequestration for the payment of any debts, judgments, alimony or separate maintenance owed by an Executive or any other person, nor be transferable by operation of law in the event of an Executive's or any other person's bankruptcy or insolvency.

10.5 Not a Contract of Employment. The terms and conditions of this Plan shall not be deemed to constitute a contract of employment between the Corporation and the Executive, and the Executive (or the Executive's Beneficiary) shall have no rights against the Corporation except as may otherwise be specifically provided herein. Moreover, nothing in this Plan shall be deemed to give an Executive the right to be retained in the service of the Corporation or to interfere with the right of the Corporation to discipline or discharge the Executive at any time.

10.6 Protective Provision. An Executive will cooperate with the Corporation by furnishing any and all information requested by the Corporation, in order to facilitate the payment of benefits hereunder, and by taking such physical examinations as the Corporation may deem necessary and taking such other actions as may be requested by the Corporation.

10.7 Governing Law. The provisions of this Plan shall be construed and interpreted according to the laws of the State of Oregon, except as preempted by federal law.

10.8 Validity. In case any provision of this Plan shall be held illegal or invalid for any reason, said illegality or invalidity shall not affect the remaining parts hereof, but this Plan shall be construed and enforced as if such illegal and invalid provisions had never been inserted herein.

10.9 Notice. Any notice or filing required or permitted to be given to the Committee under the Plan shall be sufficient if in writing and hand delivered, or sent by registered or certified mail, to any member of the Committee or the Secretary of the Corporation. Such notice shall be deemed given as of the date of delivery or, if delivery is made by mail, as of the date shown on the postmark on the receipt for registration or certification.

10.10 Successors. The provisions of this Plan shall bind and inure to the benefit of the Corporation and its successors and assigns. The term successors as used herein shall include any corporate or other business entity which shall, whether by merger, consolidation, purchase or otherwise, acquire all or substantially all of the business and assets of the Corporation, and successors of any such corporation or other business entity.

NORTHWEST NATURAL GAS COMPANY

By: /s/ Mark S. Dodson

Attest:

Section 13: EX-10.F (DIRECTORS DEFERRED COMPENSATION PLAN, EFFECTIVE JUNE 1, 1981)

Exhibit 10f.

NORTHWEST NATURAL GAS COMPANY

DIRECTORS DEFERRED COMPENSATION PLAN

EFFECTIVE JUNE 1, 1981

RESTATED AS OF FEBRUARY 28, 2008

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NORTHWEST NATURAL GAS COMPANY

DIRECTORS DEFERRED COMPENSATION PLAN

1. Restatement. The Board of Directors (the "Board") of Northwest Natural Gas Company (hereinafter, the "Company") adopted a Director's Deferred Compensation Plan (hereinafter, the "Plan") effective June 1, 1981, which was previously restated effective as of January 1, 1988, December 1, 1997, December 1, 2001, February 26, 2004, December 15, 2005 and January 1, 2007. The Plan was partially terminated in accordance with Paragraph 9(b)(i) effective December 31, 2004, so deferrals of compensation are no longer being made under the Plan. The Plan is now amended and restated by this Restatement, effective as of February 28, 2008.

2. Election by Directors.

(a) Eligibility. Any director of the Company or any corporation or other entity affiliated with or subsidiary to it (a "Director") is eligible to elect to defer receipt of all or part of (i) the fees paid to him or her as a Director or as a member of a committee of the Board ("Fees"), or (ii) the shares ("NEDSCP Shares") of restricted common stock of the Company ("Common Stock") awarded to the Director under the Company's Non-Employee Directors Stock Compensation Plan ("NEDSCP"). In addition, a Director may elect under the NEDSCP to receive awards under that plan as deferred cash credits ("NEDSCP Cash Credits") rather than as NEDSCP Shares.

(b) Deferral of Fees. Any Director may elect, prior to the beginning of any calendar year, to defer receipt of fees for that calendar year, whether or not the fees are actually payable in that calendar year; and any newly elected Director prior to assuming office may elect to defer receipt of fees commencing after the date on which the Director assumes office. Any election under the preceding sentence shall apply only to fees earned subsequent to the date the election is filed. Total deferrals of Fees by a Director in a calendar year must be at least $1,500.

(c) Deferral of NEDSCP Shares. Any Director may elect, prior to the beginning of any calendar year, to defer receipt of unvested NEDSCP Shares that are scheduled to vest in that calendar year; and any newly elected Director prior to assuming office may elect to defer receipt of NEDSCP Shares that will vest in the remainder of the calendar year after the date on which the Director assumes office. Total deferrals of NEDSCP Shares by a Director in a calendar year must be at least 100% of the NEDSCP Shares scheduled to vest in that year. No deferral shall be allowed of NEDSCP Shares as to which a Director has made an election under Section 83(b) of the Internal Revenue Code.

(d) Continuation and Modification. An election to defer Fees or NEDSCP Shares by a Director shall automatically continue from year to year unless the Director terminates or modifies the election by written request. Any such termination or modification shall not become applicable until the calendar year following the year in which such written termination or modification is filed. In the event of a termination of a deferral election, any amounts already deferred by a Director shall not be paid until he or she ceases to serve as a Director, and then only pursuant to the terms, conditions, limitations and restrictions of the Plan.

3. Accounts.

(a) Accounts. The Company shall establish on its books one, two or three separate accounts (individually, an "Account" and collectively, the "Accounts") for each Director who participates in the Plan: a Stock Account, a Cash Account, and/or for each person who is a Director as of January 1, 1998, a Retirement Benefit Account. The number of NEDSCP Shares deferred by a Director shall be credited to the Stock Account. Any NEDSCP Cash Credits shall be credited to the Cash Account. Fees deferred by a Director shall be credited to the Stock Account or the Cash Account as elected by the Director at the time the Director elects to defer Fees. Such election may be divided between the two Accounts in increments of 25 percent of the deferred Fees covered by the election. An election between the Stock Account and the Cash Account shall be irrevocable as to the deferred Fees covered by the election and no transfers between the Stock Account and the Cash Account shall be permitted except as otherwise provided in Paragraph 3(f)(iv). The credit for deferred Fees shall be entered on the Company's books of account each month at the time that Fees are paid to other Directors who do not elect to defer the payment of such Fees. The credit for deferred NEDSCP Shares shall be entered on the Company's books of account as soon as practicable after January 1 of the year subject to the deferral. The credit for an NEDSCP Cash Credit shall be entered on the Company's books of account effective as of the award date for such credit under the NEDSCP. No special fund shall be established nor shall any notes or securities be issued by the Company with respect to a Director's Accounts.

(b) Stock Account. A Director's Stock Account shall be denominated in shares of Common Stock, including fractional shares. With respect to each amount of Fees deferred to a Director's Stock Account, the Stock Account shall be credited with a number of shares equal to the deferred Fees divided by the purchase price for shares of Common Stock under the Company's Dividend Reinvestment and Direct Stock Purchase Plan (the "DRSPP") on the Investment Date (as defined in the DRSPP) next succeeding the day the deferred Fees would have been paid if not for the deferral. As of each date for payment of dividends on the Common Stock, the Stock Accounts shall be credited with an additional number of shares (including fractional shares) equal to the amount of dividends that would be paid on the number of shares recorded as the balance of the Stock Account as of the record date for such dividend divided by closing market price of the Common Stock reported for such payment date or, if such day is not a trading day, the next trading day.

(c) Forfeiture of NEDSCP Shares or NEDSCP Cash Credits. If any NEDSCP Shares deferred by a Director under this Plan are forfeited under the terms of the NEDSCP, the Director's Stock Account shall be reduced by the number of shares so forfeited. If any NEDSCP Cash Credits of a Director are forfeited under the terms of the NEDSCP, the Director's Cash Account shall be reduced by the amount of NEDSCP Cash Credits so forfeited.

(d) Retirement Benefit Account. A Director's Retirement Benefit Account shall be denominated in shares of Common Stock, including fractional shares. Effective as of January 1, 1998, Section 5 of Article III of the Company's Bylaws has been amended to eliminate with respect to all persons who are Directors as of January 1, 1998 a provision for a retirement benefit payable to Directors who retire from the Board at age 72 with at least 10 years of service. Effective as of January 1, 1998, the Retirement Benefit Account of each person who is a Director on that date shall be credited with a number a shares of Common Stock determined by the Company as a replacement for the prior retirement benefit. As of each date for payment of dividends on the Common Stock, the Retirement Benefit Accounts shall be credited with an additional number of shares (including fractional shares) equal to the amount of dividends that would be paid on the number of shares recorded as the balance of the Retirement Benefit Account as of the record date for such dividend divided by the purchase price for shares of Common Stock under the DRSPP for dividends reinvested on such payment date. The Retirement Benefit Account of any Director who has not ceased to be a Director prior to February 28, 2008 shall be fully vested and noncancellable effective as of February 28, 2008.

(e) Statement of Account. At the end of each calendar quarter, a report shall be issued by the Company to each participating Director setting forth the balances of the Director's Accounts under the Plan. The credit entries made to a Director's Accounts constitute merely a general obligation of the Company to pay such Accounts to the Director, or to his or her beneficiary or estate when due under the Plan.

(f) Effect of Corporate Transaction on Stock Accounts and Retirement Benefit Accounts. At the time of consummation of a Corporate Transaction, if any, the amount credited to a Director's Stock Account and Retirement Benefit Account shall be converted into a credit for cash or common stock of the acquiring company ("Acquiror Stock") based on the consideration received by shareholders of the Company in the Corporate Transaction, as follows:

(i) Stock Transaction. If holders of Common Stock receive Acquiror Stock in the Corporate Transaction, then (1) the amount credited to each Director's Stock Account and/or Retirement Benefit Account shall be converted into a credit for the number of shares of Acquiror Stock that the Director would have received as a result of the Corporate Transaction if the Director had actually held the Common Stock credited to his or her Stock Account and/or Retirement Benefit Account immediately prior to the consummation of the Corporate Transaction, and (2) Stock Accounts and Retirement Benefit Accounts will thereafter be denominated in shares of Acquiror Stock and ongoing deferrals of Fees and NEDSCP Shares, if any, shall continue to be made in accordance with outstanding deferral elections into the Stock Accounts as so denominated.

(ii) Cash or Other Property Transaction. If holders of Common Stock receive cash or other property in the Corporate Transaction, then (1) the amount credited to a Director's Stock Account and/or Retirement Benefit Account shall be transferred to the Director's Cash Account and converted into a cash credit for the amount of cash or the value of the property that the Director would have received as a result of the Corporate Transaction if the Director had actually held the Common Stock credited to his or her Stock Account and/or Retirement Benefit Account immediately prior to the consummation of the Corporate Transaction, and (2) Stock Accounts shall no longer exist under the Plan and all ongoing deferrals, if any, shall thereafter be made into Cash Accounts.

(iii) Combination Transaction. If holders of Common Stock receive Acquiror Stock and cash or other property in the Corporate Transaction, then (1) the amount credited to each Director's Stock Account and/or Retirement Benefit Account shall be converted in part into a credit for Acquiror Stock under Paragraph 3(f)(i) and in part into a credit for cash under Paragraph 3(f)(ii) in the same proportion as such consideration is received by shareholders, and (2) ongoing deferrals of Fees and NEDSCP Shares, if any, shall continue to be made in accordance with outstanding deferral elections into Stock Accounts in accordance with Paragraph 3(f)(i).

(iv) Election Following Stock Transaction. For a period of 12 months following the consummation of any Corporate Transaction which results in Directors having Stock Accounts and/or Retirement Benefit Accounts denominated in Acquiror Stock, each Director shall have a one-time right to elect to transfer the entire amount in the Director’s Stock Account and Retirement Benefit Account into the Director’s Cash Account; provided, however, that this election shall not be available if the Corporate Transaction results in holders of Common Stock becoming holders of all of the outstanding common stock of a parent corporation of the Company. Such election shall be made by written notice to the Company and shall be effective on the date received by the Company. If such an election is made, the amount of cash to be credited to the Director’s Cash Account shall be determined by multiplying the number of shares of Acquiror Stock in the Director’s Stock Account and Retirement Benefit Account by the closing market price of the Acquiror Stock reported for the last trading day preceding the effective date of the election.

4. Interest. Interest shall be credited to the Cash Account balance (including both principal and interest) of each participating Director based on the balance at the end of each calendar quarter. The rate of interest to be applied at the end of each calendar quarter is set forth below in this Paragraph 4. The interest credit shall continue to be applied to the Cash Account of a Director, even if ceasing to serve as a Director, until all amounts credited to his or her Cash Account have been paid. Said interest shall be calculated quarterly, based upon the average daily balance of the Director’s Cash Account since the preceding calendar quarter, after giving effect to any reduction in the Cash Account as a result of any payments. The remaining annual payments will be recomputed to reflect the additional interest credits.

The rate of interest to be applied at the end of each calendar quarter shall be the quarterly equivalent of an annual yield that is two percentage points (2%) higher than the annual yield on Moody’s Average Corporate Bond Yield for the preceding quarter, as published by the Moody’s Investors Service, Inc. (or any successor thereto), or if such index is no longer published, a substantially similar index selected by the Board. At no time shall the rate of interest be less than six percent (6%) annually. Notwithstanding the foregoing, effective as of January 1, 2017, the rate of interest to be applied at the end of each calendar quarter shall be the rate of interest for interest credited to cash accounts under the Company’s Deferred Compensation Plan for Directors and Executives, as such plan may be amended from time to time (the "DCPDE"), regardless of whether or not such rate of interest shall be more or less than six percent (6%) annually; provided, however, that if at any time on or after January 1, 2017 there is no interest credited to cash accounts under the DCPDE because the DCPDE shall have ceased to operate or for any other reason, then, at such time on or after January 1, 2017, the rate of interest to be applied at the end of each calendar quarter shall be the quarterly equivalent of an annual yield that is equal to the annual yield on Moody’s Average Corporate Bond Yield for the preceding quarter, as published by Moody’s Investors Service, Inc. (or any successor thereto), or, if such index is no longer published, a substantially similar index selected by the Board, regardless of whether or not such rate of interest shall be more or less than six percent (6%) annually. Any change in the rate of interest that occurs on January 1, 2017 or thereafter pursuant to the provisions of this paragraph shall not constitute an "amendment affecting the interest rate" within the meaning of Paragraph 9(a) below.

5. Terms of Payment.

(a) Plan Benefits. The amounts contained in a Director's Accounts are subject to the terms of payment as set forth in this paragraph. When a Director ceases to serve as a Director of the Company, either by retirement or otherwise, the individual shall be entitled to payment of the amounts in his or her Accounts.

(b) Timing of Benefit Payment. At the time the Director elects to defer Fees or NEDSCP Shares or to receive NEDSCP Cash Credits in lieu of NEDSCP Shares, and with respect to Retirement Benefit Accounts before January 1, 1998, the Director may designate the number of annual installments, not to exceed ten, in which the applicable Account balance shall be paid, or the Director may elect to receive such Account balance in a lump sum payment, or in a combination of a partial lump sum and the remainder in installment payments. A Director may elect to modify such election by filing a change of payment designation which shall supersede the prior form of payment designation for any one (1) or more deferral periods; provided, however, that a Director may not file a change of payment designation with respect to amounts credited to his or her Retirement Benefit Account after December 31, 2008. If the Director's most recent change of payment designation has not been filed one (1) full calendar year prior to the year in which the Director ceases to serve as a Director of the Company, the prior election shall be used to determine the form of payment. For example, a Director leaving the Board in 2003 must file a written request with the Committee by December 31, 2001 to change his form of payment designation.

(c) Form of Benefit Payment. Benefits payable to a Director from a Stock Account or a Retirement Benefit Account shall only be paid to such Director as a distribution of Common Stock plus cash for fractional shares. Benefits payable to a Director from a Cash Account shall only be paid to such Director in cash.

(d) Commencement of Payment. Any lump sum payment or the first annual installment payment owed to a Director shall not be due earlier than the first business day of January in the year following the year in which he or she ceases to serve as a Director of the Company. In the event a Director terminates the election to defer Fees or NEDSCP Shares, any Fees or NEDSCP Shares already deferred shall not be payable to the Director until such time as he or she ceases to serve as a Director, and then only subject to the terms and conditions contained herein. The provisions of this paragraph are subject to the terms of Paragraph 6 covering the death of a Director and to the terms of Paragraph 8 covering a Change in Control.

(e) Payment to Guardian. If a benefit under the Plan is payable to a minor or a person declared incompetent or to a person incapable of handling the disposition of his property, the Committee may direct payment of such Plan benefit to the guardian, legal representative or person responsible for the care and custody of such minor, incompetent or person. The Committee may require proof of incompetence, minority, incapacity or guardianship as it may deem appropriate prior to distribution of the Plan benefit. Such distribution shall completely discharge the Committee and the Company from all liability with respect to such benefit.

(f) Withholding; Payroll Taxes. The Company shall withhold from payments made hereunder any taxes required to be withheld from such payments under federal, state or local law.

(g) Accelerated Distribution. Notwithstanding any other provision of the Plan, a Director shall be entitled to receive, upon written request to the Committee, a lump sum distribution equal to ninety percent (90%) of the total balance of the Director's Cash Account and Stock Account as of the last day of the calendar quarter immediately preceding the day on which the Committee receives the written request. The remaining balance of the Director's Cash Account and Stock Account shall be forfeited by the Director. No accelerated distribution under this section shall be available for amounts in Directors' Retirement Benefit Accounts. A Director who receives a distribution under this section shall be suspended from participation in the Plan for 12 months, but such suspension shall not apply to crediting of NEDSCP Cash Credits. The amount payable under this section shall be paid in a lump sum within 65 days following the receipt of the notice by the Committee from the Director.

6. Death of Director.

(a) Plan Death Benefit. Upon the death of a Director or a former Director prior to the receipt of the full amount credited to his or her Accounts, the balance of the Director's Accounts shall be paid to the designated beneficiary or beneficiaries in the manner elected in writing by the Director at the time of the deferral election, or if no such election is made, by lump sum payment.

(b) Beneficiary. At the time a Director elects to defer payment of Fees or NEDSCP Shares or to receive NEDSCP Cash Credits in lieu of NEDSCP Shares, and with respect to Retirement Benefit Accounts before January 1, 1998, the Director may designate a beneficiary or beneficiaries. If greater than 50% of the benefit is designated to a beneficiary other than the Director's spouse, such beneficiary designation shall be consented to by the Director's spouse. Such designation may be changed by the Director at any time without the consent of a beneficiary, subject to the spousal consent requirement above. If no designated beneficiary survives the Director or former Director, the balance of the Director's Accounts shall be paid to the Director's estate.

7. Administration.

(a) Committee Duties. This Plan shall be administered by the Organization and Executive Compensation Committee of the Board (the "Committee"). The Committee shall have responsibility for the general administration of the Plan and for carrying out its intent and provisions. The Committee shall interpret the Plan and have such powers and duties as may be necessary to discharge its responsibilities. The Committee may, from time to time, employ other agents and delegate to them such administrative duties as it sees fit, and may from time to time consult with counsel who may be counsel to the Company.

(b) Binding Effect of Decisions. The decision or action of the Committee in respect of any question arising out of or in connection with the administration, interpretation and application of the Plan and the rules and regulations promulgated hereunder shall be final and conclusive and binding upon all persons having any interest in the Plan.

(c) Indemnity of Committee. To the extent permitted by applicable law, the Company shall indemnify, hold harmless and defend the members of the Committee against any and all claims, loss, damage, expense or liability arising from any action or failure to act with respect to this Plan, provided that the members of the Committee were acting in accordance with the applicable standard of care.

8. Definitions; Change in Control; Corporate Transaction.

(a) For purposes of this Plan, a "Change in Control" of the Company shall mean the occurrence of any of the following events:

(i) The consummation of:

(A) any consolidation, merger or plan of share exchange involving the Company (a "Merger") as a result of which the holders of outstanding securities of the Company ordinarily having the right to vote for the election of directors ("Voting Securities") immediately prior to the Merger do not continue to hold at least 50% of the combined voting power of the outstanding Voting Securities of the surviving corporation or a parent corporation of the surviving corporation immediately after the Merger, disregarding any Voting Securities issued to or retained by such holders in respect of securities of any other party to the Merger; or

(B) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of the Company;

(ii) At any time during a period of two consecutive years, individuals who at the beginning of such period constituted the board of directors of the Company ("Incumbent Directors") shall cease for any reason to constitute at least a majority thereof; provided, however, that the term "Incumbent Director" shall also include each new director elected during such two-year period whose nomination or election was approved by two-thirds of the Incumbent Directors then in office; or

(iii) Any person (as such term is used in Section 14(d) of the Securities Exchange Act of 1934, other than the Company or any employee benefit plan sponsored by the Company) shall, as a result of a tender or exchange offer, open market purchases or privately negotiated purchases from anyone other than the Company, have become the beneficial owner (within the meaning of Rule 13d-3 under the Securities Exchange Act of 1934), directly or indirectly, of Voting Securities representing twenty percent (20%) or more of the combined voting power of the then outstanding Voting Securities.

(b) For purposes of this Plan, a "Corporate Transaction" shall mean any of the following:

(i) any consolidation, merger or plan of share exchange involving the Company pursuant to which shares of Common Stock would be converted into cash, securities or other property; or

(ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of the Company.

9. Amendment and Termination of the Plan.

(a) Amendment. The Board may at any time amend the Plan in whole or in part; provided, however, that upon a Change in Control, no amendment shall be effective to change the payout schedule in Paragraph 9(b)(ii), and further provided that no amendment shall decrease or restrict the amount credited to any Account maintained under the Plan as of the date of amendment. An amendment affecting the interest rate credited under Paragraph 4 shall not become effective before the first day of the calendar year which follows the adoption of the amendment and at least 30 days written notice of the amendment to the Director. An amendment affecting the interest rate credited under Paragraph 4 that is adopted after a Change in Control shall apply only to those amounts credited to Directors' Accounts after the Change in Control.

(b) Termination. The Board may at any time partially or completely terminate the Plan if, in its judgment, the tax, accounting, or other effects of the continuance of the Plan, or potential payments thereunder, would not be in the best interests of the Company.

(i) Partial Termination. The Board may partially terminate the Plan by instructing the Committee not to accept any additional deferrals. In the event of such a partial termination, the Plan shall continue to operate and be effective with regard to deferrals entered into prior to the effective date of such partial termination.

(ii) Complete Termination. The Board may completely terminate the Plan by instructing the Committee not to accept any additional deferrals, and terminate all ongoing deferrals. The Plan shall cease to operate and the Committee shall pay out to each Director the balance in each of his or her Accounts in a lump sum or in equal annual installments amortized over the period listed in the payout schedule below based on the balance in the particular Account at the time of such complete termination:

Payout Schedule

Appropriate Account Balance	Payout Period
Less than $10,000	Lump sum
$10,000 but less than $50,000	Lesser of 5 years or period elected in Participation Agreement
More than $50,000	Period elected in Participation Agreement

Interest earned on the unpaid balance in the Director's Cash Account shall be the applicable interest rate at the end of the calendar quarter immediately preceding the effective date of such complete termination.

10. Miscellaneous.

(a) Unsecured General Creditor. The Accounts shall be established solely for the purpose of measuring the amounts owed to a Director or beneficiary under the Plan. Directors and their beneficiaries, heirs, successors and assigns shall have no legal or equitable rights, interest or claims in any property or assets of the Company, nor shall they be beneficiaries of, or have any rights, claims or interests in any life insurance policies, annuity contracts or the proceeds therefrom owned or which may be acquired by the Company. Except as may be provided in Paragraph 10(b), such policies, annuity contracts or other assets of the Company shall not be held under any trust for the benefit of the Directors, their beneficiaries, heirs, successors or assigns, or held in any way as collateral security for the fulfilling of the obligations of the Company under this Plan. Any and all of the Company's assets and policies shall be, and remain, the general, unpledged, unrestricted assets of the Company. The Company's obligation under the Plan shall be that of an unfunded and unsecured promise to pay money in the future.

(b) Trust Fund. The Company shall be responsible for the payment of all benefits provided under the Plan. At its discretion, the Company may establish one or more trusts, with such trustees as the Board may approve, for the purpose of providing for the payment of such benefits. Such trust or trusts may be irrevocable, but the assets thereof shall be subject to the claims of the Company's creditors. To the extent any benefits provided under the Plan are actually paid from any such trust, the Company shall have no further obligation with respect thereto, but to the extent not so paid, such benefits shall remain the obligation of, and shall be paid by, the Company.

(c) Nonassignability. No assignment or alienation may be made of any deferred fees or interest thereon, except in accordance with Paragraph 6.

(d) Governing Law. The provisions of this Plan shall be construed and interpreted according to the laws of the State of Oregon.

(e) Successors. The provisions of this Plan shall bind and inure to the benefit of the Company and its successors and assigns. The term successors as used herein shall include any corporate or other business entity which shall, whether by merger, consolidation, purchase or otherwise acquire all or substantially all of the business and assets of the Company, and successors of any such corporation or other business entity.

(f) The foregoing restatement of the Plan was approved by the Board of Directors of Northwest Natural Gas Company effective as of February 28, 2008.

NORTHWEST NATURAL GAS COMPANY

By: /s/ Mark S. Dodson

Attest:________________________

Section 14: EX-10.F(1) (DEFERRED COMPENSATION PLAN FOR DIRECTORS AND EXECUTIVES EFFECTIVE JANUARY 1)

Exhibit 10f.(1)

NORTHWEST NATURAL GAS COMPANY

DEFERRED COMPENSATION PLAN FOR DIRECTORS AND EXECUTIVES

EFFECTIVE JANUARY 1, 2005

RESTATED FEBRUARY 28, 2008

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NORTHWEST NATURAL GAS COMPANY

DEFERRED COMPENSATION PLAN FOR DIRECTORS AND EXECUTIVES

1. Purpose; Effective Date; Restatement. The Board of Directors (the "Board") of Northwest Natural Gas Company (the "Company") adopts this Deferred Compensation Plan for Directors and Executives (the "Plan") for the purpose of providing an unfunded nonqualified deferred compensation plan for directors and a select group of top management personnel. The Plan was effective as of January 1, 2005, although initial deferral elections under the Plan could have been submitted at any time after November 30, 2004. The Plan was previously restated effective January 1, 2007 and December 20, 2007, and is further amended by this restatement, on and effective as of February 28, 2008, except that the changes to Section 6(b) made by this restatement shall not apply to deferral allocations made in Participation Agreements that were irrevocable on or prior to December 31, 2006.

2. Eligibility. Persons eligible to defer compensation under the Plan shall consist of (a) all directors of the Company ("Directors"), and (b) a select group of management or highly compensated employees of the Company, which shall consist of all executive officers of the Company and such other employees of the Company as may be designated in writing by the Chief Executive Officer of the Company as eligible to defer compensation under the Plan for the applicable calendar year ("Executives"). Any person who is both a Director and an Executive at any time shall be considered an Executive, and not a Director, at such time. For all purposes of this Plan, a person who is an employee of a subsidiary of the Company shall be considered an employee of the Company.

3. Deferral Elections. A Director or Executive may elect to defer compensation under the Plan by submitting a "Participation Agreement" to the Company on a form specified by the Company no later than the applicable deferral deadline. The minimum annual aggregate deferral for all forms of compensation specified in a Participation Agreement shall be $2,000. Any Director or Executive who has submitted a Participation Agreement is hereafter referred to as a "Participant." A Participation Agreement submitted by a Participant shall automatically continue from year to year and shall be irrevocable with respect to compensation once the deferral deadline for that compensation has passed, but the Participant may modify or terminate a Participation Agreement for compensation payable in any year by submitting a revised Participation Agreement or otherwise giving written notice to the Company at any time on or prior to the deferral deadline for that compensation.

(a) Elections by Directors.

(i) Fees. A Director may elect to defer receipt of all or any whole percentage of the annual retainer, meeting fees and any other cash fees payable for service as a director ("Fees"). The deferral deadline for an election to defer Fees for services performed in any calendar year shall be the last day of the prior calendar year.

(ii) NEDSCP Shares. A Director may elect to defer receipt of all or any whole percentage of the unvested shares ("NEDSCP Shares") of common stock of the Company ("Common Stock") awarded to the Director under the Company's Non-Employee Directors Stock Compensation Plan ("NEDSCP"). The deferral deadline for an election to defer NEDSCP Shares scheduled to vest in any calendar year shall be the last day of the prior calendar year, except that the deferral deadline for an election to defer NEDSCP Shares scheduled to vest on January 1 in any calendar year shall be the last day of the second preceding calendar year. No deferral shall be allowed of NEDSCP Shares as to which a Director has made an election under Section 83(b) of the Internal Revenue Code.

(b) Elections by Executives.

(i) Salary. An Executive may elect to defer receipt of any whole percentage (up to a maximum of 50 percent) of the Executive's base annual salary, specifically excluding other forms of compensation referred to below as well as commissions and any non-cash compensation ("Salary"). The deferral deadline for an election to defer Salary for services performed in any calendar year shall be the last day of the prior calendar year.

(ii) Bonus. An Executive may elect to defer receipt of all or any whole percentage of the Executive's annual bonus payable under the Company's Executive Annual Incentive Plan or other similar annual incentive plan ("Bonus"). Payments under the Key Goals program shall not be considered Bonus and shall not be eligible for deferral under the Plan. The deferral deadline for an election to defer Bonus earned with respect to the Executive's or the Company's performance in any calendar year shall be the last day of the prior calendar year.

(iii) LTIP Compensation. An Executive may elect to defer receipt of all or any whole percentage of compensation payable to the Executive pursuant to an award under the Company's Long Term Incentive Plan ("LTIP Compensation"); provided, however, that no election shall be permitted after December 31, 2008 to defer receipt of an award that becomes payable or vests based solely on continued service to the Company ("Time-Based Award"). The deferral deadline for an election to defer any portion of a Time-Based Award shall be the date that is 12 months prior to the date on which such portion of the Time-Based Award is scheduled to no longer be subject to a substantial risk of forfeiture. The deferral deadline for an election to defer LTIP Compensation that becomes payable or vests based on satisfaction of performance conditions over a performance period ("Performance Award") shall be the last day of the calendar year prior to the commencement of the performance period; provided, however, that for any Performance Award for which the performance period ends on or before December 31, 2008, the deferral deadline shall be the last day of the calendar year prior to the last year of the performance period, and for any Performance Award for which the performance period ends on December 31, 2009 or December 31, 2010, the deferral deadline shall be December 31, 2008.

(c) New Directors and Executives. A person who first becomes a Director or Executive during a calendar year may elect to defer any of the types of compensation referred to in paragraphs (a) and (b) above that is payable solely for services performed after submission of the Participation Agreement, subject to all of the provisions of paragraphs (a) and (b), except that the deferral deadline for any such election shall be 30 days after the date the person becomes eligible under the Plan.

4. Company Contributions for Executives.

(a) Matching Contributions. The Company shall credit a "Matching Contribution" to a participating Executive's Cash Account (as defined below) each year based on the Executive's total Salary and Bonus and the amount of Salary and Bonus deferred under the Plan by the Executive during that year; provided, however, that no Matching Contribution shall be made with respect to any Salary or Bonus deferred under the Plan at a time when the Executive is not a participant in the Company's Retirement K Savings Plan. The amount of the Matching Contribution shall be equal to the excess of (i) the lesser of (1) sixty percent (60%) of the total amount of Executive's Salary and Bonus deferred under the Plan and the Retirement K Savings Plan during the calendar year, or (2) three and six-tenths percent (3.6%) of the Executive's total Salary and Bonus during such calendar year, over (ii) the amount the Company would have contributed for such calendar year as a matching contribution for the Executive under the Retirement K Savings Plan if the Executive had deferred into the Retirement K Savings Plan the maximum amount of compensation permitted under that plan and applicable tax law for the year. Matching Contributions shall be credited to the Executive's Account no later than January 31 of the year immediately following the calendar year in which the Matching Contribution was earned, and shall be fully vested at all times.

(b) Supplemental Contributions. For any Executive who is hired after December 31, 2006 and is therefore eligible to receive non-contributory employer contributions under Section 4.05 of the Retirement K Savings Plan, the Company shall credit a "Supplemental Contribution" to the Executive's Cash Account each year in an amount equal to five percent (5%) of the greater of (i) the Executive's Salary and Bonus deferred under the Plan during the calendar year, or (ii) the excess, if any, of the Executive's total Salary and Bonus during such calendar year over the limit provided by Section 401(a)(17) of the Internal Revenue Code on compensation counted under the Retirement K Savings Plan for that year. A Supplemental Contribution shall be credited for an Executive whose total Salary and Bonus exceeds the Section 401(a)(17) limit whether or not the Executive defers compensation under the Plan. Supplemental Contributions shall be credited to the Executive's Account no later than January 31 of the year immediately following the calendar year in which the Supplemental Contribution was earned. Supplemental Contributions for an Executive shall be vested if non-contributory employer contributions for the Executive made for the same year would be vested under the terms of the Retirement K Savings Plan**.** Upon termination of an Executive's employment, any unvested Supplemental Contributions, as well as any dividends or interest credited thereon, shall be forfeited and deducted from the Executive's Accounts.

5. FICA Withholding on Executives. Under current law, all compensation, Matching Contributions and vested Supplemental Contributions credited to an Executive's Accounts will be treated as wages subject to FICA tax, and the Company will be required to withhold FICA tax from the Executive. The amount required to be withheld for FICA tax with respect to any amount of deferred compensation or related Matching Contribution or Supplemental Contribution shall be withheld from the non-deferred portion, if any, of the same compensation; provided, however, that if the non-deferred portion of the compensation is insufficient to cover the full required withholding, the Company shall withhold the remaining amount from other non-deferred compensation payable to the Executive unless the Executive otherwise pays such remaining amount to the Company.

6. Accounts.

(a) Accounts. The Company shall establish on its books one or two separate accounts (individually, an "Account" and collectively, the "Accounts") for each Participant: a Company Stock Account, which shall be denominated in shares of Common Stock, including fractional shares, and a Cash Account, which shall be denominated in U.S. dollars.

(b) Allocation of Deferrals Among Accounts. The number of NEDSCP Shares deferred by a Director shall be credited to the Company Stock Account. All LTIP Compensation payable in shares of Common Stock that is deferred by an Executive shall be credited to the Company Stock Account. All other compensation deferred by a Participant shall be credited to the Cash Account.

(c) Crediting of Deferrals. The credits for deferred Salary, Bonus and Fees shall be entered on the Company's books of account at the time that such compensation would otherwise be paid. The credit for deferred NEDSCP Shares shall be entered on the Company's books of account as soon as practicable after January 1 of the first year in which such deferral is irrevocable. The credit for any LTIP Compensation deferred by an Executive consisting of shares of Common Stock issued subject to forfeiture if vesting conditions are not satisfied ("Unvested LTIP Shares") shall be entered on the Company's books of account as soon as practicable after such deferral is irrevocable. The credit for any other deferred LTIP Compensation shall be entered on the Company's books of account at the time that such compensation would otherwise be paid.

(d) Transfers Among Accounts. Participants may elect in writing to transfer amounts previously credited to the Cash Account to the Company Stock Account, but shall be limited to four such transfers per calendar year. No transfers may be made out of a Company Stock Account unless otherwise permitted under Section 6(i)(iv). The Committee may require that designated fees be deducted from amounts transferred to or from Company Stock Accounts.

(e) Valuation of Stock; Dividend Credits. Any dollar amount transferred or credited to a Company Stock Account shall be deemed to increase the number of shares of Common Stock recorded as the balance of that Account based on the closing market price of the Common Stock reported for the day of the transfer or credit or, if such day is not a trading day, the next trading day. As of each date for payment of dividends on the Common Stock, each Company Stock Account shall be credited with the amount of dividends that would be paid on the number of shares recorded as the balance of that Account as of the record date for such dividend.

(f) Cash Account Interest. Interest shall be credited to the Cash Account of each Participant as of the last day of each calendar quarter. The rate of interest to be applied at the end of each calendar quarter shall be the quarterly equivalent of an annual yield that is equal to the annual yield on Moody's Average Corporate Bond Yield for the preceding quarter, as published by the Moody's Investors Service, Inc. (or any successor thereto), or if such index is no longer published, a substantially similar index selected by the Board. Interest shall be calculated for each calendar quarter based upon the average daily balance of the Participant's Cash Account during the quarter.

(g) Forfeitures. If any NEDSCP Shares deferred by a Director under this Plan are forfeited under the terms of the NEDSCP, the Director's Company Stock Account shall be reduced by the number of shares so forfeited. If any Unvested LTIP Shares deferred by an Executive under this Plan are forfeited under the terms of the Executive's applicable award agreement, the Executive's Company Stock Account shall be reduced by the number of shares so forfeited.

(h) Statement of Account. At the end of each calendar quarter, a report shall be issued by the Company to each Participant setting forth the balances of the Participant's Accounts under the Plan.

(i) Effect of Corporate Transaction on Company Stock Accounts. At the time of consummation of a Corporate Transaction (as defined below), if any, the amount credited to a Participant's Company Stock Account shall be converted into a credit for cash or common stock of the acquiring company ("Acquiror Stock") based on the consideration received by shareholders of the Company in the Corporate Transaction, as follows:

(i) Stock Transaction. If holders of Common Stock receive Acquiror Stock in the Corporate Transaction, then (1) the amount credited to each Participant's Company Stock Account shall be converted into a credit for the number of shares of Acquiror Stock that the Participant would have received as a result of the Corporate Transaction if the Participant had actually held the Common Stock credited to his or her Company Stock Account immediately prior to the consummation of the Corporate Transaction, and (2) Company Stock Accounts will thereafter be denominated in shares of Acquiror Stock and ongoing deferrals into Company Stock Accounts, if any, shall continue to be made in accordance with outstanding deferral elections into the Company Stock Accounts as so denominated.

(ii) Cash or Other Property Transaction. If holders of Common Stock receive cash or other property in the Corporate Transaction, then the amount credited to a Participant's Company Stock Account shall be transferred to the Participant's Cash Account and converted into a cash credit for the amount of cash or the value of the property that the Participant would have received as a result of the Corporate Transaction if the Participant had actually held the Common Stock credited to his or her Company Stock Account immediately prior to the consummation of the Corporate Transaction.

(iii) Combination Transaction. If holders of Common Stock receive Acquiror Stock and cash or other property in the Corporate Transaction, then (1) the amount credited to each Participant's Company Stock Account shall be converted in part into a credit for Acquiror Stock under Section 6(i)(i) and in part into a credit for cash under Section 6(i)(ii) in the same proportion as such consideration is received by shareholders, and (2) ongoing deferrals into Company Stock Accounts, if any, shall continue to be made in accordance with outstanding deferral elections into Company Stock Accounts in accordance with Section 6(i)(i).

(iv) Election Following Stock Transaction. For a period of 12 months following the consummation of any Corporate Transaction which results in Participants having Company Stock Accounts denominated in Acquiror Stock, each Participant shall have a one-time right to elect to transfer the entire amount in the Participant's Company Stock Account into the

Participant’s Cash Account; provided, however, that this election shall not be available if the Corporate Transaction results in holders of Common Stock becoming holders of all of the outstanding common stock of a parent corporation of the Company. Such election shall be made by written notice to the Company and shall be effective on the date received by the Company. If such an election is made, the amount of cash to be credited to the Participant’s Cash Account shall be determined by multiplying the number of shares of Acquiror Stock in the Participant’s Company Stock Account by the closing market price of the Acquiror Stock reported for the effective date of the election or, if such day is not a trading day, the next trading day.

(v) For purposes of this Plan, a "Corporate Transaction" shall mean any of the following:

(1) any consolidation, merger or plan of share exchange involving the Company (a "Merger") pursuant to which shares of Common Stock would be converted into cash, securities or other property;

(2) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of the Company; or

(3) the adoption of any plan or proposal for the liquidation or dissolution of the Company.

7. <u>Payment of Benefits</u>.

(a) <u>Plan Benefits</u>. The Company shall pay Plan benefits to each Participant equal to the Participant’s Accounts. Each Participation Agreement shall include an election by the Participant as to the term of benefit payments with respect to amounts deferred under the Participation Agreement, and Participation Agreements from Executives shall also include an election as to the commencement of benefit payments. The payment elections in a Participation Agreement shall also apply to Matching Contributions and Supplemental Contributions credited as a result of Salary or Bonus during the deferral period covered by the Participation Agreement, and shall also apply to any dividends or interest credited with respect to amounts deferred under the Participation Agreement and such Matching Contributions and Supplemental Contributions. If a Supplemental Contribution is credited to an Executive’s Account for a year that is not covered by a Participation Agreement, the Executive shall be deemed to have elected a single lump sum payment following Separation from Service as permitted by Sections 7(b) and 7(c) below with respect to benefits resulting from such Supplemental Contribution. Except as otherwise provided in this Section 7, payment elections shall be irrevocable with respect to compensation once the deferral deadline for that compensation has passed. Participants may make different payment elections with respect to subsequent deferrals of compensation, but no Participant may at any time have compensation deferred under the Plan payable under more than three different payment elections.

(b) Commencement of Payments. Payment of benefits to Directors shall commence in January of the year following the Director’s Separation from Service (as defined below) with the Company. Payment of benefits to Executives shall commence in the later of (i) January of the year following the Executive’s Separation from Service with the Company, or (ii) the seventh month following the month of the Executive’s Separation from Service with the Company; provided, however, that Executives may elect in their Participation Agreements to have benefits from their Accounts commence in January of a year specified by the Executive if such year is earlier than the year following the Executive’s Separation from Service with the Company. When used in this Plan, the term "Separation from Service" shall have the meaning ascribed to such term in Treasury Regulations §1.409A-1(h).

(c) Term of Payments. Participants may elect in their Participation Agreements to have benefits from their Accounts paid in (i) annual installments over 5, 10 or 15 years, (ii) a single lump sum payment, or (iii) a combination of a partial lump sum payment (expressed as a percentage) and the remainder in installments over 5, 10 or 15 years.

(d) Form of Payments. Benefits payable to a Participant from a Company Stock Account shall be paid as a distribution of Common Stock plus cash for fractional shares. Benefits payable to a Participant from a Cash Account shall be paid in cash.

(e) Payment Timing and Valuation. All lump sum payments or installment payments due under the Plan in any year shall be paid on a date in January determined by the Company, except that if Section 7(b) requires benefits to commence in a month other than January, the initial payment shall be paid on a date in that month determined by the Company. All payments shall be based on Account balances as of the close of business on the last trading day of the immediately preceding month. Each partial lump sum payment and installment payment to a Participant shall be paid in the same proportion from each of the Accounts of the Participant subject to the applicable payment election. The amount of each installment payment from each Account shall be determined by dividing the Account balance by the number of remaining installments, including the current installment to be paid.

(f) Modification of Payment Elections.

(i) An Executive who has elected to have any benefit commence in a specified year prior to termination of employment as permitted in Section 7(b) may elect (after such election has otherwise become irrevocable) to specify a later year for commencement of such benefit, provided that for any such election submitted after December 31, 2008, (1) such election is made in writing delivered to the Company no later than, and becoming irrevocable on, the last day of the second year preceding the previously specified year, and (2) the later year so specified is at least 5 years later than the previously specified year.

(ii) After a Participant’s election under Section 7(c) regarding the term of any benefit payments has otherwise become irrevocable, the Participant may elect to change such term of payments, provided (1) the choice of annual installments over 15 years shall not be available for a change election under this subsection, (2) the term of any particular payments may be changed only once under this subsection, (3) such election must be made in writing delivered to the Company no later than, and becoming irrevocable on, the last day of the second year preceding the year in which the payments otherwise would have commenced (and shall not be effective if a Separation from Service occurs on or before the date the election becomes irrevocable), and (4) the commencement of the affected payments shall be delayed for 5 years after the date the payments would have commenced under the terms of the previous payment election. Accordingly, for a Director who elects to change the term of any benefit payments, the commencement of those payments will be delayed until January of the year following the fifth anniversary of the Director's Separation from Service. Notwithstanding the foregoing, a Participant may elect on or prior to December 31, 2008 to change the term of any benefit payments that have not commenced as of that date without application of any of the limitations or restrictions set forth in this Section 7(f)(ii).

(g) Unforeseeable Emergency. Notwithstanding the foregoing provisions of this Section 7, an accelerated payment from a Participant's Accounts may be made to the Participant in the sole discretion of the Committee based upon a finding that the Participant has suffered an Unforeseeable Emergency. For this purpose, "Unforeseeable Emergency" means a severe financial hardship to the Participant resulting from an illness or accident of the Participant, the Participant's spouse or a dependent of the Participant, loss of the Participant's property due to casualty, or other similar extraordinary and unforeseeable circumstances arising as a result of events beyond the control of the Participant. Unforeseeable Emergency shall be determined by the Committee on the basis of information supplied by the Participant in accordance with uniform guidelines promulgated from time to time by the Committee. The amount of any accelerated payment under this Section 7(g) shall be limited to the amount reasonably necessary to meet the Participant's needs resulting from the Unforeseeable Emergency, after taking into account insurance and other potential sources of funds to meet such needs, plus the amount reasonably necessary to cover income and withholding taxes on the accelerated payment. Any such accelerated payment shall be paid as promptly as practicable following approval by the Committee and shall be paid pro-rata from the Participant's Accounts based on the account balances as of the close of business on the day prior to the payment date.

(h) Designation of Beneficiaries; Death.

(i) Each Participant shall have the right, at any time, to designate any person or persons as the Participant's beneficiary or beneficiaries (both primary as well as secondary) to whom benefits under this Plan shall be paid in the event of the Participant's death prior to complete distribution of the benefits due under the Plan. If greater than fifty percent (50%) of the benefit is designated to a beneficiary other than the Participant's spouse, such beneficiary designation shall be consented to by the Participant's spouse. Each beneficiary designation shall be in written form prescribed by the Company and will be effective only if filed with the Company during the Participant's lifetime. Such designation may be changed by the Participant at any time without the consent of a beneficiary, subject to the spousal consent requirement above. If no designated beneficiary survives the Participant, the balance of the Participant's benefits shall be paid to the Participant's surviving spouse or, if no spouse survives, to the Participant's estate.

(ii) Upon the death of a Participant, notwithstanding any contrary provisions of Section 7(b) or 7(f), benefit payments to the Participant's beneficiary shall commence no later than January of the year following the Participant's death. Any benefits payable after the death of a Participant shall otherwise be paid in accordance with the payment elections for such benefits that would have applied if the Participant had not died.

(i) Payment to Guardian. If a benefit under the Plan is payable to a minor or a person declared incompetent or to a person incapable of handling the disposition of his property, the Committee may direct payment of such Plan benefit to the guardian, legal representative or person responsible for the care and custody of such minor, incompetent or person. The Committee may require proof of incompetence, minority, incapacity or guardianship as it may deem appropriate prior to distribution of the Plan benefit. Such distribution shall completely discharge the Committee and the Company from all liability with respect to such benefit.

(j) Withholding; Payroll Taxes. The Company shall withhold from payments made hereunder any taxes required to be withheld from such payments under federal, state or local law.

8. Supplemental Retirement Benefit. Any Executive who elects to defer compensation under this Plan and who also satisfies the eligibility requirements for payment of any benefit under the Company's Retirement Plan for Non-Bargaining Unit Employees (the "Retirement Plan") shall qualify for further payment by the Company of supplemental retirement benefits payable as a monthly annuity under this Plan, as provided below:

(a) Commencement. If the Executive is eligible to receive normal retirement benefits under the Retirement Plan based on having reached age 62 at the time of Separation from Service, the annuity shall commence with the first month following the Executive's Separation from Service. If the Executive is eligible to receive early retirement benefits under the Retirement Plan based on having satisfied the Rule of 70 at the time of Separation from Service, the annuity shall commence with the first month following the later of the Executive's 55th birthday or the Executive's Separation from Service. If the Executive is eligible to receive disability retirement benefits under the Retirement Plan, the annuity shall commence with the first month following the later of the Executive's 55th birthday or the Executive's Separation from Service. If the Executive is not eligible to receive normal retirement benefits, early retirement benefits or disability retirement benefits under the Retirement Plan, but is eligible to receive vested benefits under the Retirement Plan, the annuity shall commence with the first month following the Executive's 62nd birthday. If the Executive's surviving spouse is eligible to receive death benefits under the Retirement Plan as a result of the Executive's death before commencement of benefits under this Section 8, the annuity shall commence in the month that benefits would have commenced as provided in this Section 8(a) if the Executive had a Separation from Service on the date of death (or on the Executive's actual Separation from Service, if earlier) and then survived until benefits had commenced.

(b) Form of Benefit.

(i) Annuity Form. If the Executive elects a form of annuity benefit under the Retirement Plan at least 30 days prior to the first day of the month in which the benefit under this Section 8 is required to commence, the benefit under this Section 8 shall be paid in the same annuity form as selected under the Retirement Plan. If the Executive's benefit under this Section 8 commences earlier than the Executive's benefit under the Retirement Plan, the Executive may, at least 30 days prior to the first day of the month in which the benefit under this Section 8 is required to commence and otherwise in accordance with the rules of the Retirement

Plan, elect any of the standard or optional annuity forms of benefit described in 6.01 and 6.02 of the Retirement Plan, other than a joint and survivor annuity upon marriage or remarriage after the annuity starting date. If the Executive does not make a timely election under this Section 8(b), the benefit under this Section 8 shall be paid in the default annuity form applicable to the Executive under the Retirement Plan.

(ii) Small Benefit Cash Out. If the actuarial equivalent lump sum present value of the Executive's benefit under this Section 8, based on the actuarial assumptions used for determining equivalent benefits under the Retirement Plan at the time of the Executive's commencement of benefits, is no more than the applicable dollar amount under Internal Revenue Code section 402(g)(1)(B) (which is $15,500 in 2007 and 2008), the benefit shall be paid as a lump sum in such amount at the time annuity payments would have otherwise commenced under Section 8(a).

(c) Amount. The amount payable by the Company each month to the Executive or Executive's beneficiaries under the Retirement Plan shall be:

(i) The amount that would be payable at such time under the Retirement Plan assuming that (1) benefits had commenced on the date specified in Section 8(a), (2) benefits were payable in the annuity benefit form determined under Section 8(b), (3) all accrued benefits under the Retirement Plan were payable only in the annuity form as provided in Section 8(d), and (4) all Salary and Bonus deferred by the Executive under this Plan and under the Company's former Executive Deferred Compensation Plan (the "Prior Plan") had been "paid" to or "received" by Executive in the year when the deferral was made, provided that all such deferred amounts shall be subject to the other applicable definitions and rules of the Retirement Plan relating to benefit determination; plus

(ii) The reduction, if any, in the amount of the monthly Social Security benefit payable to the Executive, provided that such reduction results from the fact that compensation deferred under this Plan causes the primary Social Security Benefit payable to the Executive to be reduced, with the amount under this Section 8(c)(ii) calculated assuming commencement of Social Security benefits at the earliest possible time, no earnings after Separation from Service and no projected increases in the national average wage index or cost of living between Separation from Service and commencement of benefits; minus

(iii) The amount that would actually be payable at such time under the Retirement Plan assuming that (1) benefits had commenced on the date specified in Section 8(a), (2) benefits were payable in the annuity benefit form determined under Section 8(b), and (3) all accrued benefits under the Retirement Plan were payable only in the annuity form as provided in Section 8(d).

(d) Retirement Plan Lump Sum Election Ignored. Notwithstanding any election by an Executive to receive a portion of Executive's Retirement Plan benefit as a lump sum, the amount of the supplemental retirement benefit as determined under Section 8(c) shall be calculated and determined as if Executive were to receive Executive's entire Retirement Plan accrued benefit in the annuity form determined under Section 8 (b).

(e) Six-Month Minimum Delay. Notwithstanding the foregoing, no supplemental retirement benefit payments under this Section 8 shall be paid to any Executive until the seventh month following the month of the Executive's Separation from Service with the Company. Any payments that would have been paid if not for this Section 8(e) shall be accumulated and paid in full in the seventh month following the month of the Executive's Separation from Service with the Company together with interest from the date each payment otherwise would have been payable until the date actually paid. Interest for any period will be paid at the same rate applicable for that period under Section 6(f).

(f) Waiver of Comparable Benefits Under Prior Plan. Because amounts deferred under the Prior Plan are taken into account in calculating the benefits payable under this Section 8, acceptance of the benefits under this Section 8 shall be deemed to be a waiver of the comparable benefits set forth in Section 5.7 of the Prior Plan.

9. Administration.

(a) Committee Duties. This Plan shall be administered by the Organization and Executive Compensation Committee of the Board (the "Committee"). The Committee shall have responsibility for the general administration of the Plan and for carrying out its intent and provisions. The Committee shall interpret the Plan and have such powers and duties as may be necessary to discharge its responsibilities. The Committee may, from time to time, employ other agents and delegate to them such administrative duties as it sees fit, and may from time to time consult with counsel who may be counsel to the Company.

(b) Tax Law Compliance. The Committee shall have the authority to cancel any Participation Agreement in whole or in part, and immediately distribute any compensation deferred under such Participation Agreement, but only to the extent the Committee determines that deferral of compensation in accordance with such Participation Agreement has or will violate Section 409A of the Internal Revenue Code and therefore has or will require immediate inclusion of such compensation in the income of the Participant.

(c) Binding Effect of Decisions. The decision or action of the Committee in respect of any question arising out of or in connection with the administration, interpretation and application of the Plan and the rules and regulations promulgated hereunder shall be final and conclusive and binding upon all persons having any interest in the Plan.

10. Claims Procedure.

(a) Claim. Any person claiming a benefit, requesting an interpretation or ruling under the Plan, or requesting information under the Plan shall present the request in writing to the Committee, which shall respond in writing as soon as practicable.

(b) Denial of Claim. If the claim or request is denied, the written notice of denial shall state:

(i) The reasons for denial, with specific reference to the Plan provisions on which the denial is based;

(ii) A description of any additional material or information required and an explanation of why it is necessary; and

(iii) An explanation of the Plan's claim review procedure.

(c) Review of Claim. Any person whose claim or request is denied or who has not received a response within thirty (30) days may request review by notice given in writing to the Committee. The claim or request shall be reviewed by the Committee who may, but shall not be required to, grant the claimant a hearing. On review, the claimant may have representation, examine pertinent documents, and submit issues and comments in writing.

(d) Final Decision. The decision on review shall normally be made within sixty (60) days. If an extension of time is required for a hearing or other special circumstances, the claimant shall be notified and the time limit shall be one hundred twenty (120) days. The decision shall be in writing and shall state the reasons and the relevant Plan provisions. All decisions on review shall be final and bind all parties concerned.

11. Amendment and Termination of the Plan.

(a) Amendment. The Board may at any time amend the Plan in whole or in part; provided, however, that no amendment shall without the consent of each affected Participant (i) decrease or restrict the amount credited to any Account maintained under the Plan as of the date of amendment, or (ii) accelerate or decelerate the payment of benefits with respect to amounts credited to any Account as of the date of the amendment.

(b) Termination. The Board may at any time partially or completely terminate the Plan if, in its judgment, the tax, accounting, or other effects of the continuance of the Plan, or potential payments thereunder, would not be in the best interests of the Company.

(i) Partial Termination. The Board may partially terminate the Plan by instructing the Committee not to accept any additional Participation Agreements and terminating deferrals under all existing Participation Agreements. In the event of such a partial termination, the Plan shall continue to operate and be effective with regard to all compensation deferred prior to the effective date of such partial termination.

(ii) Complete Termination. The Board may completely terminate the Plan, provided such termination is covered by an exception (set forth in regulations or other guidance of the Internal Revenue Service) to the prohibition on acceleration of deferred compensation. In that event, on the effective date of the complete termination, the Plan shall cease to operate and the Company shall determine the balance of each Participant's Accounts as of the close of business on such effective date. The Company shall pay out such Account balances to the Participants in a single lump sum payment as soon as practicable after such effective date.

12. Miscellaneous.

(a) Unsecured General Creditor. The Accounts shall be established solely for the purpose of measuring the amounts owed to Participants or beneficiaries under the Plan. Participants and their beneficiaries, heirs, successors and assigns shall have no legal or equitable rights, interest or claims in any property or assets of the Company, nor shall they be beneficiaries of, or have any rights, claims or interests in any mutual funds, other investment products or the proceeds therefrom owned or which may be acquired by the Company. Except as may be provided in Section 12 (b), such mutual funds, other investment products or other assets of the Company shall not be held under any trust for the benefit of the Participants, their beneficiaries, heirs, successors or assigns, or held in any way as collateral security for the fulfilling of the obligations of the Company under this Plan. Any and all of the Company's assets shall be, and remain, the general, unpledged, unrestricted assets of the Company. The Company's obligation under the Plan shall be that of an unfunded and unsecured promise to pay money in the future, and the rights of Participants and beneficiaries shall be no greater than those of unsecured general creditors of the Company.

(b) Trust Fund. The Company shall be responsible for the payment of all benefits provided under the Plan. The Company shall establish one or more trusts, with such trustees as the Board may approve, for the purpose of providing for the payment of such benefits, but the Company shall have no obligation to contribute to such trusts except as specifically provided in the applicable trust documents. Such trust or trusts shall be irrevocable, but the assets thereof shall be subject to the claims of the Company's creditors. To the extent any benefits provided under the Plan are actually paid from any such trust, the Company shall have no further obligation with respect thereto, but to the extent not so paid, such benefits shall remain the obligation of, and shall be paid by, the Company.

(c) Non-assignability. Neither a Participant nor any other person shall have the right to commute, sell, assign, transfer, pledge, anticipate, mortgage or otherwise encumber, transfer, hypothecate or convey in advance of actual receipt the amounts, if any, payable hereunder, or any part thereof, which are, and all rights to which are, expressly declared to be non-assignable and nontransferable. No part of the amounts payable shall, prior to actual payment, be subject to seizure or sequestration for the payment of any debts, judgments, alimony or separate maintenance owed by a Participant or any other person, nor be transferable by operation of law in the event of a Participant's or any other person's bankruptcy or insolvency.

(d) Not a Contract of Employment. The terms and conditions of this Plan shall not be deemed to constitute a contract of employment between the Company and any Participant, and the Participants (and their beneficiaries) shall have no rights against the Company except as may otherwise be specifically provided herein. Moreover, nothing in this Plan shall be deemed to give a Participant the right to be retained in the service of the Company or to interfere with the right of the Company to discipline or discharge the Participant at any time.

(e) Governing Law. The provisions of this Plan shall be construed and interpreted according to the laws of the State of Oregon, except as preempted by federal law.

(f) Validity. In case any provision of this Plan shall be held illegal or invalid for any reason, said illegality or invalidity shall not affect the remaining parts hereof, but this Plan shall be construed and enforced as if such illegal and invalid provisions had never been inserted herein.

(g) Notice. Any notice or filing required or permitted to be given to the Company or the Committee under the Plan shall be sufficient if in writing and hand delivered, or sent by registered or certified mail, to the Secretary of the Company. Such notice shall be deemed given as of the date of delivery or, if delivery is made by mail, as of the date shown on the postmark on the receipt for registration or certification.

(h) Successors. The provisions of this Plan shall bind and inure to the benefit of the Company and its successors and assigns. The term successors as used herein shall include any corporate or other business entity which shall, whether by merger, consolidation, purchase or otherwise acquire all or substantially all of the business and assets of the Company, and successors of any such corporation or other business entity.

The foregoing restatement of the Plan was approved by the Board of Directors of Northwest Natural Gas Company effective as of February 28, 2008.

NORTHWEST NATURAL GAS COMPANY

By: /s/ Mark S. Dodson

Attest: ______________________

Section 15: EX-10.W(2) (FORM OF LONG-TERM INCENTIVE AWARD AGREEMENT UNDER THE LONG-TERM INCENTIVE PLAN)

Exhibit 10w.2

LONG TERM INCENTIVE AWARD AGREEMENT

This Agreement is entered into as of February __, 2008, between Northwest Natural Gas Company, an Oregon corporation (the "Company"), and _________ ("Recipient").

On February __, 2008, the Organization and Executive Compensation Committee (the "Committee") of the Company’s Board of Directors (the "Board") authorized an objectively-determinable performance-based award (the "TSR Award") to Recipient pursuant to Section 8 of the Company’s Long Term Incentive Plan (the "Plan") and a subjective performance-based award (the "Strategic Award") to Recipient pursuant to Section 6 of the Plan. Compensation paid pursuant to the TSR Award is intended to qualify as performance-based compensation under Section 162(m) of the Internal Revenue Code of 1986 (the "Code"), while compensation paid pursuant to the Strategic Award will not so qualify. Recipient desires to accept the awards subject to the terms and conditions of this Agreement.

NOW, THEREFORE, the parties agree as follows:

1. Awards. Recipient’s "Target Share Amount" for purposes of this Agreement is _________ shares.

1.1 TSR Award. Subject to the terms and conditions of this Agreement, the Company shall issue or otherwise deliver to the Recipient the number of shares of Common Stock of the Company (the "TSR Performance Shares") determined under this Agreement based on (a) the performance of the Company’s Common Stock relative to a peer group of companies during the three-year period from January 1, 2008 to December 31, 2010 (the "Award Period") as described in Section 2 and (b) Recipient’s continued employment during the Award Period as described in Section 4. If the Company issues or otherwise delivers TSR Performance Shares to Recipient, the Company shall also pay to Recipient the amount of cash determined under Section 5 (the "TSR Dividend Equivalent Cash Award"). Recipient’s "TSR Target Share Amount" for purposes of this Agreement is 75% of the Target Share Amount.

1.2 Strategic Award. Subject to the terms and conditions of this Agreement, the Company shall issue or otherwise deliver to the Recipient the number of shares of Common Stock of the Company (the "Strategic Performance Shares" and, together with the TSR Performance Shares, the "Performance Shares") determined under this Agreement based on (a) the Company’s performance against milestones during the Award Period as determined by the Committee under Section 3 and (b) Recipient’s continued employment during the Award Period as described in Section 4. If the Company issues or otherwise delivers Strategic Performance Shares to Recipient, the Company shall also pay to Recipient the amount of cash determined under Section 5 (the "Strategic Dividend Equivalent Cash Award" and, together with the TSR Dividend Equivalent Cash Award, the "Dividend Equivalent Cash Awards"). Recipient’s "Strategic Target Share Amount" for purposes of this Agreement is 25% of the Target Share Amount.

2. TSR Performance Condition.

2.1 Subject to possible reduction under Section 4, the number of TSR Performance Shares to be issued or otherwise delivered to Recipient shall be determined by multiplying the TSR Payout Factor (as defined below) by the TSR Target Share Amount; provided, however, that no TSR Performance Shares shall be issued or otherwise delivered unless the Company’s TSR (as defined below) for the Award Period is at least 19.1%.

2.2 To determine the "TSR Payout Factor," the ten Peer Group Companies (as defined below) shall be ranked based on their respective TSR’s from highest to lowest, with the Peer Group Company with the highest TSR having a TSR Ranking of "1" and the Peer Group Company with the lowest TSR having a TSR Ranking of "10." If the Company’s TSR is equal to the TSR of any other Peer Group Company, the TSR Payout Factor will be the percentage in the following table corresponding to the TSR Ranking of that Peer Group Company.

TSR Ranking	TSR Payout Factor
10	0%
9	0%
8	25%
7	25%
6	50%
5	75%
4	100%
3	125%
2	150%
1	200%

If the Company’s TSR is higher than the TSRs of all Peer Group Companies, the TSR Payout Factor will be 200%. If the Company’s TSR is not at least as high as the TSR of the Peer Group Company with the TSR Ranking of "8," the TSR Payout Factor will be 0%. If the Company’s TSR is between the TSRs of any two Peer Group Companies with TSR Rankings between "1" and "8," the TSR Payout Factor shall be interpolated as follows. The excess of the Company’s TSR over the TSR of the lower Peer Group Company shall be divided by the excess of the TSR of the higher Peer Group Company over the TSR of the lower Peer Group Company. The resulting fraction shall be multiplied by the difference between the percentages in the above table corresponding to the TSR Rankings of the two Peer Group Companies. The product of that calculation shall be added to the percentage in the above table corresponding to the TSR Ranking of the lower Peer Group Company, and the resulting sum shall be the TSR Payout Factor.

2.3 The "Peer Group Companies" are AGL Resources Inc., Atmos Energy Corporation, The Laclede Group, Inc., New Jersey Resources Corporation, NICOR Inc., Piedmont Natural Gas Company, Inc., South Jersey Industries, Inc., Southwest Gas Corporation, Vectren Corporation and W G L Holdings, Inc. If prior to the end of the Award Period, the common stock of any Peer Group Company ceases to be publicly traded for any reason, then such company shall no longer be considered a Peer Group Company, and an alternate peer company shall become a Peer Group Company effective as of the start of the Award Period. The alternate peer companies, and the order in which they will be added as Peer Group Companies, if necessary, are: first, NiSource Inc.; second, Chesapeake Utilities Corporation; and third, National Fuel Gas Company. If prior to the end of the Award Period, all of the above alternate peer companies have become Peer Group Companies and the common stock of yet another Peer Group Company ceases to be publicly traded for any reason so that there are only nine remaining

Peer Group Companies, for purposes of Section 2.2 it shall be assumed that there is a hypothetical Peer Group Company with a TSR Ranking of "5"; provided, however, that if the Company's TSR is between the TSRs of the Peer Group Companies with TSR Rankings of "4" and "6," the TSR Payout Factor shall be interpolated between the payout percentages corresponding to the TSR Rankings of those two companies. If yet another Peer Group Company ceases to be publicly traded for any reason so that there are only eight remaining Peer Group Companies, for purposes of Section 2.2 it shall be assumed that there are two hypothetical Peer Group Company with TSR Rankings of "5" and "6" and, if necessary, the TSR Payout Factor shall interpolated between the payout percentages corresponding to the Peer Group Companies with TSR Rankings of "4" and "7". Similarly, if additional Peer Group Companies cease to be publicly traded for any reason, additional hypothetical Peer Group Companies shall be assumed to exist with TSR Rankings of "4", then "7", then "3", then "9", and then "2".

2.4 The "TSR" for the Company and each Peer Group Company shall be calculated by (a) assuming that $100 is invested in the common stock of the company at a price equal to the average of the closing market prices of the stock for the period from October 1, 2007 to December 31, 2007, (b) assuming that for each dividend paid on the stock during the Award Period, the amount equal to the dividend paid on the assumed number of shares held is reinvested in additional shares at a price equal to the closing market price of the stock on the ex-dividend date for the dividend, and (c) determining the final dollar value of the total assumed number of shares based on the average of the closing market prices of the stock for the period from October 1, 2010 to December 31, 2010. The "TSR" shall then equal the amount determined by subtracting $100 from the foregoing final dollar value, dividing the result by 100 and expressing the resulting fraction as a percentage.

2.5 If during the Award Period any Peer Group Company enters into an agreement pursuant to which all or substantially all of the stock or assets of the Peer Group Company will be acquired by a third party (a "Signed Acquisition"), and if the Signed Acquisition is not completed so that such company remains a Peer Group Company at the end of the Award Period, then the calculation of the TSR for that Peer Group Company shall be modified as provided in this Section 2.5. A "Partial Period TSR" for each Peer Group Company shall be calculated in the same manner as TSR is calculated under Section 2.4, except that for this purpose the Award Period shall be deemed to have ended on the day before the date of announcement of the Signed Acquisition and the final dollar value under clause (c) of Section 2.4 for each Peer Group Company shall be determined based on the average of the closing market prices of each stock for the three-month period ending on the day before such announcement date. The TSR of the Peer Group Company subject to the Signed Acquisition shall then be equal to its Partial Period TSR multiplied by the Average Change Factor (as defined below). The "Average Change Factor" shall be a fraction, the numerator of which is the average of the TSRs of all Peer Group Companies that are not subject to a Signed Acquisition, and the denominator of which is the average of the Partial Period TSRs of those Peer Group Companies. If a Signed Acquisition of a Peer Group Company is terminated (other than in connection with the execution of another Signed Acquisition) before the end of the Award Period, then the above modification to the calculation of TSR for that Peer Group Company shall not apply, and the TSR for that Peer Group Company shall be calculated as provided in Section 2.4, except that if the announcement of the termination of the Signed Acquisition occurs during the last three months of the Award Period, for purposes of determining the final dollar value under clause (c) of Section 2.4, the three-month period for which closing market prices are averaged shall be shortened to exclude any trading days preceding the announcement of the termination of the Signed Acquisition.

3. Strategic Performance Condition. Subject to possible reduction under Section 4, the number of Strategic Performance Shares to be issued or otherwise delivered to Recipient shall be determined by multiplying the Strategic Payout Factor by the Strategic Target Share Amount. The "Strategic Payout Factor" shall be a percentage between 0% and 200% determined by the Committee after the Award Period based on the Committee's assessment of the extent to which the Company has achieved the following goals during the Award Period:

[applicable goals]

4. Employment Condition.

4.1 In order to receive the full number of Performance Shares determined under Section 2 or Section 3, Recipient must be employed by the Company on the last day of the Award Period.

4.2 If Recipient’s employment by the Company is terminated at any time prior to the end of the Award Period because of death, physical disability (within the meaning of Section 22(e)(3) of the Code), or retirement (as defined in the Company’s Retirement Plan for Non-Bargaining Unit Employees) at or after reaching age 60, Recipient shall be entitled to receive pro-rated awards. The number of each type of Performance Shares to be issued or otherwise delivered as a pro-rated award shall be determined by multiplying the number of Performance Shares determined under Section 2 or Section 3 by a fraction, the numerator of which is the number of days Recipient was employed by the Company during the Award Period and the denominator of which is the number of days in the Award Period.

4.3 If Recipient’s employment by the Company is terminated at any time prior to the end of the Award Period and Section 4.2 does not apply to such termination, Recipient shall not be entitled to receive any Performance Shares.

5. Dividend Equivalent Cash Awards. The amount of each type of Dividend Equivalent Cash Award shall be determined by multiplying the number of Performance Shares deliverable to Recipient as determined under Sections 2 and 4 or under Sections 3 and 4, as applicable, by the total amount of dividends paid per share of the Company’s Common Stock for which the dividend record date occurred after the beginning of the Award Period and before the date of delivery of the Performance Shares.

6. Certification and Payment. At the regularly scheduled meeting of the Committee held in February of the year immediately following the final year of the Award Period (the "Certification Meeting"), the Committee shall determine the Strategic Payout Factor and certify in writing (which may consist of approved minutes of the Certification Meeting) the number of Strategic Performance Shares deliverable to Recipient and the amount of the Strategic Dividend Equivalent Cash Award payable to Recipient. Prior to the Certification Meeting, the Company shall calculate the number of TSR Performance Shares deliverable and the amount of the TSR Dividend Equivalent Cash Award payable to Recipient, and shall submit these calculations to the Committee. At or prior to the Certification Meeting, the Committee shall certify in writing (which may consist of approved minutes of the Certification Meeting) the levels of TSR attained by the Company and the Peer Group Companies, the number of TSR Performance Shares deliverable to Recipient and the amount of the TSR Dividend Equivalent Cash Award payable to Recipient. Subject to applicable tax withholding, the amounts so certified shall be delivered or paid (as applicable) on a date (the "Payment Date") that is the later of March 1, 2011 or five business days following the Certification Meeting, and no amounts shall be delivered or paid

prior to certification. No fractional shares shall be delivered and the number of Performance Shares deliverable shall be rounded to the nearest whole share. Notwithstanding the foregoing, if Recipient shall have made a valid election to defer receipt of Performance Shares or Dividend Equivalent Cash Awards pursuant to the terms of the Company's Deferred Compensation Plan for Directors and Executives, payment of the award shall be made in accordance with that election.

7. Tax Withholding. Recipient acknowledges that, on the Payment Date when the Performance Shares are issued or otherwise delivered to Recipient, the Value (as defined below) on that date of the Performance Shares (as well as the amount of the Dividend Equivalent Cash Awards) will be treated as ordinary compensation income for federal and state income and FICA tax purposes, and that the Company will be required to withhold taxes on these income amounts. To satisfy the required withholding amount, the Company shall first withhold all or part of the Dividend Equivalent Cash Awards, and if that is insufficient, the Company shall withhold the number of Performance Shares having a Value equal to the remaining withholding amount. For purposes of this Section 7, the "Value" of a Performance Share shall be equal to the closing market price for Company Common Stock on the last trading day preceding the Payment Date. Notwithstanding the foregoing, Recipient may elect not to have Performance Shares withheld to cover taxes by giving notice to the Company in writing prior to the Payment Date, in which case the Performance Shares shall be issued or acquired in the Recipient's name on the Payment Date thereby triggering the tax consequences, but the Company shall retain the certificate for the Performance Shares as security until Recipient shall have paid to the Company in cash any required tax withholding not covered by withholding of the Dividend Equivalent Cash Awards.

8. Change in Control.

8.1 If a Change in Control (as defined below) occurs before the end of the Award Period, the Company shall, within 5 business days thereafter and subject to applicable tax withholding as provided for in Section 7, issue or otherwise deliver to Recipient a number of Performance Shares determined by multiplying the CIC Share Amount (as defined below) by a fraction, the numerator of which is the number of days in the period starting on the first day of the Award Period and ending on the date of the Change of Control and the denominator of which is the number of days in the Award Period. At the same time, the Company shall pay to Recipient a Dividend Equivalent Cash Award based on such number of Performance Shares. The "CIC Share Amount" shall equal 100% of the Strategic Target Share Amount plus an amount equal to the CIC TSR Payout Factor (as defined below) multiplied by the TSR Target Share Amount. The "CIC TSR Payout Factor" shall be determined in the same manner as the TSR Payout Factor is determined under Section 2 of this Agreement, except that the final dollar value under clause (c) of Section 2.4 for the Company and each Peer Group Company shall be determined based on the average of the closing market prices of each stock for the three-month period ending on the date of the Change of Control; provided, however, that the CIC TSR Payout Factor shall be zero percent if the Company's TSR as computed for this purpose does not represent at least a 6% annual return (cumulated annually) for the period starting on the first day of the Award Period and ending on the date of the Change of Control. Amounts delivered or paid under this Section 8 shall be in satisfaction of any and all obligations of the Company to issue or otherwise deliver Performance Shares or pay Dividend Equivalent Cash Awards under this Agreement.

8.2 For purposes of this Agreement, a "Change in Control" of the Company shall mean the occurrence of any of the following events:

(a) The consummation of:

(1) any consolidation, merger or plan of share exchange involving the Company (a "Merger") as a result of which the holders of outstanding securities of the Company ordinarily having the right to vote for the election of directors ("Voting Securities") immediately prior to the Merger do not continue to hold at least 50% of the combined voting power of the outstanding Voting Securities of the surviving corporation or a parent corporation of the surviving corporation immediately after the Merger, disregarding any Voting Securities issued to or retained by such holders in respect of securities of any other party to the Merger; or

(2) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all, or substantially all, the assets of the Company;

(b) At any time during a period of two consecutive years, individuals who at the beginning of such period constituted the Board ("Incumbent Directors") shall cease for any reason to constitute at least a majority thereof; provided, however, that the term "Incumbent Director" shall also include each new director elected during such two-year period whose nomination or election was approved by two-thirds of the Incumbent Directors then in office; or

(c) Any person (as such term is used in Section 14(d) of the Securities Exchange Act of 1934, other than the Company or any employee benefit plan sponsored by the Company) shall, as a result of a tender or exchange offer, open market purchases or privately negotiated purchases from anyone other than the Company, have become the beneficial owner (within the meaning of Rule 13d-3 under the Securities Exchange Act of 1934), directly or indirectly, of Voting Securities representing twenty percent (20%) or more of the combined voting power of the then outstanding Voting Securities.

9. Changes in Capital Structure.

9.1 If the outstanding Common Stock of the Company is hereafter increased or decreased or changed into or exchanged for a different number or kind of shares or other securities of the Company by reason of any stock split, combination of shares or dividend payable in shares, recapitalization or reclassification, appropriate adjustment shall be made by the Committee in the number and kind of shares subject to this Agreement so that the Recipient’s proportionate interest before and after the occurrence of the event is maintained.

9.2 If the outstanding Common Stock of the Company is hereafter converted into or exchanged for all of the outstanding Common Stock of a corporation (the "Parent Successor") as part of a transaction (the "Transaction") in which the Company becomes a wholly-owned subsidiary of Parent Successor, then (a) the obligations under this Agreement shall be assumed by Parent Successor and references in this Agreement to the Company shall thereafter generally be deemed to refer to Parent Successor, (b) Common Stock of Parent

Successor shall be issued in lieu of Common Stock of the Company under this Agreement, (c) the performance measured pursuant to Sections 2 and 3 of this Agreement shall be the continuous performance of the Company prior to the Transaction and Parent Successor after the Transaction, (d) employment by the Company for purposes of Section 4 of this Agreement shall include employment by either the Company or Parent Successor, and (e) the Dividend Equivalent Cash Awards under Section 5 of this Agreement shall be based on dividends paid on the Common Stock of the Company prior to the Transaction and Parent Successor after the Transaction.

9.3 Amendment of Prior Agreements. Recipient is a party to one or more agreements relating to prior performance-based awards under the Plan. Each of those prior agreements is hereby amended to add to such agreement the language set forth above in Section 9.2 of this Agreement.

10. Approvals. The issuance by the Company of authorized and unissued shares or reacquired shares under this Agreement is subject to the approval of the Oregon Public Utility Commission and the Washington Utilities and Transportation Commission, but no such approvals shall be required for the purchase of shares on the open market for delivery to Recipient in satisfaction of its obligations under this Agreement. The obligations of the Company under this Agreement are otherwise subject to the approval of state and federal authorities or agencies with jurisdiction in the matter. The Company will use its best efforts to take steps required by state or federal law or applicable regulations, including rules and regulations of the Securities and Exchange Commission and any stock exchange on which the Company's shares may then be listed, in connection with the award under this Agreement. The foregoing notwithstanding, the Company shall not be obligated to issue or deliver Common Stock under this Agreement if such issuance or delivery would violate applicable state or federal law.

11. No Right to Employment. Nothing contained in this Agreement shall confer upon Recipient any right to be employed by the Company or to continue to provide services to the Company or to interfere in any way with the right of the Company to terminate Recipient's services at any time for any reason, with or without cause.

12. Miscellaneous.

12.1 Entire Agreement; Amendment. This Agreement constitutes the entire agreement of the parties with regard to the subjects hereof and may be amended only by written agreement between the Company and Recipient.

12.2 Notices. Any notice required or permitted under this Agreement shall be in writing and shall be deemed sufficient when delivered personally to the party to whom it is addressed or when deposited into the United States Mail as registered or certified mail, return receipt requested, postage prepaid, addressed to the Company, Attention: Corporate Secretary, at its principal executive offices or to Recipient at the address of Recipient in the Company's records, or at such other address as such party may designate by ten (10) days' advance written notice to the other party.

12.3 Assignment; Rights and Benefits. Recipient shall not assign this Agreement or any rights hereunder to any other party or parties without the prior written consent of the Company. The rights and benefits of this Agreement shall inure to the benefit of and be enforceable by the Company's successors and assigns and, subject to the foregoing restriction on assignment, be binding upon Recipient's heirs, executors, administrators, successors and assigns.

12.4 Further Action. The parties agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of this Agreement.

12.5 Applicable Law; Attorneys' Fees. The terms and conditions of this Agreement shall be governed by the laws of the State of Oregon. In the event either party institutes litigation hereunder, the prevailing party shall be entitled to reasonable attorneys' fees to be set by the trial court and, upon any appeal, the appellate court.

12.6 Counterparts. This Agreement may be executed in two or more counterparts, each of which shall be deemed an original.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement as of the day and year first above written.

NORTHWEST NATURAL GAS COMPANY

By ____________________

Title____________________

RECIPIENT

____

Section 16: EX-10.BB (CONSENT TO AMENDMENT OF DEFERRED COMPENSATION PLAN)

Exhibit 10bb.

CONSENT TO AMENDMENT OF
DEFERRED COMPENSATION PLAN FOR DIRECTORS AND EXECUTIVES

This Consent to Amendment of Deferred Compensation Plan for Directors and Executives is entered into by the undersigned participants in the Deferred Compensation Plan for Directors and Executives (the "Plan") of Northwest Natural Gas Company (the "Company") on February 28, 2008.

On February 28, 2008, the Board of Directors of the Company approved amendments to the Plan (the "Amendments") reflected on the attached marked copy of the Plan. Before the Amendments, the Plan permitted Plan participants to elect to have deferrals of shares of Company Common Stock issuable under the Long Term Incentive Plan ("LTIP") credited to either Cash Accounts or Company Stock Accounts under the Plan. The Amendments eliminate the choice to credit such deferred shares to Cash Accounts, and therefore require that all deferrals of shares under the LTIP be credited to Company Stock Accounts under the Plan. The undersigned Plan participants have previously elected to defer all or a portion of the shares that may be issued to them under outstanding LTIP awards on or about March 1, 2009, and to have the value of those deferred shares credited to their Cash Accounts under the Plan. The effect of the Amendments is that their previous elections to credit deferred shares to Cash Accounts will be disregarded, and the shares they elected to defer will instead be credited to Company Stock Accounts.

Although the Plan permits the Board of Directors to adopt the Amendments without the consent of Plan participants, because the Amendments may be viewed as adversely affecting Plan participants who had previously elected to have deferred shares credited to Cash Accounts under the Plan, the Company has requested that those Plan participants consent to the Amendments.

The undersigned Plan participants hereby consent to the Amendments.

/s/ Mark S. Dodson
Mark S. Dodson

/s/ Lea Anne Doolittle
Lea Anne Doolittle

/s/ Gregg S. Kantor
Gregg S. Kantor

/s/ David A. Weber
David A. Weber

/s/ J. Keith White
J. Keith White