NORTHWEST NATURAL GAS CO
Form 10-K
February 27, 2015

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, 2014
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ___________ to____________
Commission file number 1-15973

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

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

220 N.W. Second Avenue, Portland, Oregon 97209
(Address of principal executive offices) (Zip Code)
Registrant's telephone number, including area code: (503) 226-4211

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

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes [X] No [ ]
Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes [ ] No [X]
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.
Yes [X] No [ ]
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes [X] No [ ]
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.
[ ]
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller

reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
Large Accelerated Filer [X] Accelerated Filer [ ]
Non-accelerated Filer [ ] Smaller Reporting Company [ ]
Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).
Yes [ ] No [X]
As of June 30, 2014, the registrant had 27,171,581 shares of its Common Stock outstanding, of which 26,805,283 shares were held by non-affiliates. The aggregate market value of the 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 $1,263,869,093.
At February 20, 2015, 27,304,169 shares of the registrant’s Common Stock (the only class of Common Stock) were outstanding.
DOCUMENTS INCORPORATED BY REFERENCE
Portions of the Proxy Statement of the registrant, to be filed in connection with the 2015 Annual Meeting of Shareholders, are incorporated by reference in Part III.

NORTHWEST NATURAL GAS COMPANY
Annual Report to Securities and Exchange Commission on Form 10-K
For the Fiscal Year Ended December 31, 2014

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GLOSSARY OF TERMS AND ABBREVIATIONS

AFUDC	Allowance for Funds Used During Construction
AM Best	A.M. Best Co. is a global independent credit rating agency
AOCI / AOCL	Accumulated Other Comprehensive Income (Loss)
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update as issued by the FASB
Average Weather	The 25-year average heating degree days based on temperatures established in our last Oregon general rate case.
Bcf	Billion cubic feet, a volumetric measure of natural gas, where one Bcf is roughly equal to 10 million therms.
Btu	British thermal unit, a basic unit of thermal energy measurement. One Btu equals the energy required to raise one pound of water one degree Fahrenheit at an atmospheric pressure of one and 60 degrees Fahrenheit. One hundred thousand Btus equal one therm.
CAP	Compliance Assurance Process with the Internal Revenue Service
CNG	Compressed Natural Gas
CO_2	Carbon Dioxide
Core Utility Customers	Residential, commercial and industrial customers receiving firm service from the utility.
Cost of Gas	The delivered cost of natural gas sold to customers, including the cost of gas purchased or withdrawn/produced from storage inventory or reserves, gains and losses from gas commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use.
CPUC	California Public Utilities Commission. The entity that regulates our California gas storage business at our Gill Ranch facility with respect to rates and terms of service, among other matters.
Decoupling	A billing rate mechanism, also referred to as our conservation tariff, which is designed to break the link between utility earnings and the quantity of natural gas sold to customers. The design is intended to allow the utility to encourage industrial and small commercial customers to conserve energy while not adversely affecting its earnings due to reductions in sales volumes.
Demand Cost	A component in core utility customer rates representing the cost of securing firm pipeline capacity, whether the capacity is used or not.
Dth	Dekatherm (also decatherm) is equal to 10 therms or one million British thermal units (Btu).
EBITDA	Earnings before interest, taxes, depreciation and amortization, a non-GAAP measurement.
EE/CA	Engineering Evaluation / Cost Analysis
Encana	Encana Oil & Gas Inc.
Energy Corp	Northwest Energy Corporation, a wholly-owned subsidiary of NW Natural
EPA	Environmental Protection Agency
EPS	Earnings per share
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission. The entity regulating interstate storage services offered by our Mist gas storage facility as part of our gas storage segment.
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.
FMB	First Mortgage Bonds
GAAP	Accounting principles generally accepted in the United States of America

General Rate Case	A periodic filing with state or federal regulators to establish billing rates for utility customers.
GHG	Greenhouse gases
Gill Ranch	Gill Ranch Storage, LLC, a wholly-owned subsidiary of NWN Gas Storage

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Gill Ranch Facility	Underground natural gas storage facility near Fresno, California, with 75% owned by Gill Ranch and 25% owned by PG&E.
GTN	Gas Transmission Northwest, which owns a transmission pipeline serving California and the Pacific Northwest.
Heating Degree Days	Units of measure reflecting temperature-sensitive consumption of natural gas, calculated by subtracting the average of a day's high and low temperatures from 65 degrees Fahrenheit.
HATFA	Highway and Transportation Funding Act of 2014
Interruptible Service	Natural gas service offered to customers (usually large commercial or industrial users) under contracts or rate schedules that allow for interruptions when necessary to meet the needs of firm service customers.
IRP	Integrated Resource Plan
IRS	United States Internal Revenue Service
KB	Kelso-Beaver Pipeline, of which 10% is owned by K-B Pipeline Company, a subsidiary of NNG Financial
LIBOR	London Interbank Offered Rate
LNG	Liquefied Natural Gas. The cryogenic liquid form of natural gas. To reach a liquid form at atmospheric pressure, natural gas must be cooled to approximately negative 260 degrees Fahrenheit.
LWG	Lower Willamette Group
MAP-21	A federal pension plan funding law called the Moving Ahead for Progress in the 21st Century Act, July 2012.
Moody's	Moody's Investors Service, Inc. is a credit rating agency.
NAV	Net Asset Value
NNG Financial	NNG Financial Corporation, a wholly-owned subsidiary of NW Natural
NOL	Net Operating Loss
NWN Energy	NW Natural Energy, LLC, a wholly-owned subsidiary of NW Natural
NWN Gas Reserves	NW Natural Gas Reserves, LLC, a wholly-owned subsidiary of Northwest Energy Corporation
NWN Gas Storage	NW Natural Gas Storage, LLC, a wholly-owned subsidiary of NWN Energy
OPEIU	Office and Professional Employees International Union Local No. 11, AFL-CIO, which is also referred to as the Union representing NW Natural's bargaining unit employees.
OPUC	Public Utility Commission of Oregon. The entity that regulates our Oregon utility business with respect to rates and terms of service, among other matters. The OPUC also regulates our Mist gas storage facility's intrastate storage services.
PBGC	Pension Benefit Guaranty Corporation
PG&E	Pacific Gas & Electric Company is a 25% owner of the Gill Ranch Facility.
PGA	Purchased Gas Adjustment. A regulatory mechanism which adjusts customer rates to reflect changes in the forecasted cost of gas and differences between forecasted and actual gas costs from the prior year.
PGE	Portland General Electric
PHMSA	U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration
RI/FS	Portland Harbor Remedial Investigation / Feasibility Study
ROE	Return on Equity. 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 use in determining utility revenue requirements.
ROR	Rate of Return
S&P	

	Standard & Poor's, a division of The McGraw-Hill Companies, Inc., is a credit rating agency.
Sales Service	Service provided whereby a customer purchases both natural gas commodity supply and transportation from the utility.
SEC	U.S. Securities and Exchange Commission

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SIP	System Integrity Program. An Oregon billing rate mechanism that provides cost recovery of pipeline system integrity programs, which are required under various safety standards prescribed by both state and federal regulators.
SRRM	Site Remediation and Recovery Mechanism. An Oregon billing rate mechanism for recovering prudently incurred environmental site remediation costs through customer billings, subject to an earnings test.
TAIL	TransCanada American Investments, Ltd., a 50% owner of TWH
Therm	The basic unit of natural gas measurement, equal to one hundred thousand Btu’s.
TWH	Trail West Holdings, LLC (formerly Palomar Gas Holdings, LLC), which is 50% owned by NWN Energy
TWP	Trail West Pipeline, LLC, a subsidiary of TWH (formerly Palomar Gas Transmissions, LLC)
TransCanada	TransCanada Pipelines Limited, owner of TAIL and GTN
Transportation Service	Service provided whereby a customer purchases natural gas commodity directly from a supplier but pays the utility to transport the gas over its distribution system to the customer’s facility.
Utility Margin	A financial measure consisting of utility operating revenues less the associated cost of gas and franchise tax.
VIE	Variable Interest Entity
Weather Normalization	An Oregon billing rate mechanism applied to residential and commercial customers to adjust for temperature variances from average weather. Rates decrease when the weather is colder than average, and rates increase when the weather is warmer than average. The mechanism is applied to customer bills from December through May of each heating season.
WUTC	Washington Utilities and Transportation Commission. The entity that regulates our Washington utility business with respect to rates and terms of service, among other matters.

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FORWARD-LOOKING STATEMENTS

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

- plans;
- objectives;
- goals;
- strategies;
- assumptions and estimates;
- future events or performance;
- trends;
- risks;
- timing and cyclicality;
- earnings and dividends;
- capital structure;
- growth;
- customer rates;
- commodity costs;
- gas reserves;
- operational performance and costs;
- energy policy and preferences;
- efficacy of derivatives and hedges;
- liquidity and financial positions;
- project and program development, expansion, or investment;
- competition;
- procurement and development of gas supplies;
- estimated expenditures;
- costs of compliance;
- credit exposures;
- potential efficiencies;
- rate or regulatory recovery or refunds;
- impacts of laws, rules and regulations;
- tax liabilities or refunds;
- levels and pricing of gas storage contracts;
- outcomes and effects of potential claims, litigation, regulatory actions, and other administrative matters;
- projected obligations under retirement plans;
- availability, adequacy, and shift in mix, of gas supplies;
- approval and adequacy of regulatory deferrals;
- effects of regulatory mechanisms; and
- environmental, regulatory, litigation and insurance costs and recoveries, and timing thereof.

Forward-looking statements are based on our current expectations and assumptions regarding our business, the economy and other future conditions. Because forward-looking statements relate to the future, they are subject to inherent uncertainties, risks and changes in circumstances that are difficult to predict. Our actual results may differ materially from those contemplated by the forward-looking statements. We therefore caution you against relying on any of these forward-looking statements. They are neither statements of historical fact nor guarantees or assurances of future performance. Important factors that could cause actual results to differ materially from those in the forward-looking statements are discussed at Item 1A., "Risk Factors" of Part I and Item 7. and Item 7A., "Management’s Discussion and Analysis of Financial Condition and Results of Operations" and "Quantitative and Qualitative Disclosures About Market Risk", respectively, of Part II of this report.

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

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NORTHWEST NATURAL GAS COMPANY
PART I

ITEM 1. BUSINESS

OVERVIEW

Northwest Natural Gas Company (NW Natural or the Company) was incorporated under the laws of Oregon in 1910. However, our company and its predecessors have supplied gas service to the public since 1859, and we have been doing business as NW Natural since 1997. We maintain operations in Oregon, Washington, and California and conduct business through NW Natural and its subsidiaries. References in this discussion to "Notes" are the Notes to the Consolidated Financial Statements in Item 8 of this report.

We have two core businesses: our regulated local gas distribution business, referred to as the utility segment, which serves residential, commercial, and industrial customers in Oregon and southwest Washington; and our gas storage businesses, referred to as the gas storage segment, which provides storage services for utilities, gas marketers, electric generators, and large industrial users from storage facilities located in Oregon and California. In addition, we have investments and other non-utility activities that we aggregate and report as other.

The utility business is our largest segment, while our gas storage businesses account for the majority of our remaining net income. The following table reflects the percentage allocation between segments and other as of December 31, 2014:

	Utility	Non-Utility[1] Gas Storage[2]	Other	Total
Assets	90.5 %	9.0 %	0.5 %	100.0 %
Net Income	99.8 %	(0.6)%	0.8 %	100.0 %

(1) We refer to our gas storage segment and other as non-utility as they are not included in our regulated gas distribution business; however, certain aspects of the gas storage segment and other may be regulated by the OPUC, WUTC, CPUC, or FERC.

(2) Gas Storage segment includes asset management services for both the utility and non-utility portion of our Mist gas storage facility.

LOCAL GAS DISTRIBUTION "UTILITY"

The utility is principally engaged in the regulated distribution of natural gas in Oregon and southwest Washington to over 700,000 customers with approximately 89% of our customers located in Oregon and 11% located in Washington. In total, we provide natural gas service to over 100 cities in 18 counties with an estimated population of 3.5 million in our service territory.

We have been allocated an exclusive service territory by the OPUC and WUTC, which includes a major portion of western Oregon, including the Portland metropolitan area,

most of the Willamette Valley, the Coastal area from Astoria to Coos Bay, and portions of Washington along the Columbia River. Portland serves as one of the largest international ports on the West Coast and is a key distribution center due to its comprehensive transportation system of ocean and river shipping, transcontinental railways and highways, and an international airport. Major businesses in the retail, manufacturing, and high-technology industries are located in our service territory.

Customers

We serve residential, commercial and industrial customers with no individual customer or industry accounting for more than 10% of our utility revenues. On an annual basis, residential and commercial customers typically account for around 60% of our utility's total volumes delivered and 90% of our utility's margin. Industrial customers largely account for the remaining volumes and utility margin. The following table presents summary customer information as of December 31, 2014:

	Number of Customers	% of Volumes		% of Utility Margin (1)	
Residential	637,411	35	%	64	%
Commercial	66,304	22	%	28	%
Industrial	929	43	%	8	%
Total	704,644	100	%	100	%

(1) Utility margin is also derived from other items, including miscellaneous services, gains or losses from our incentive gas cost sharing mechanism, and other service fees.

Generally residential and commercial customers purchase both their natural gas commodity (gas sales) and natural gas delivery services (transportation services) from the utility. Industrial customers also purchase transportation services from the utility, but may buy the gas commodity either from the utility or directly from a third-party gas marketer or supplier. Our gas commodity cost is primarily a pass-through cost to customers; therefore, our profit margins are not materially affected by an industrial customer's decision to purchase gas from us or from third parties. Industrial and large commercial customers may also select between firm and interruptible service levels, with firm services generally providing higher profit margins compared to interruptible services.

To help manage gas supplies, our industrial tariffs are designed to provide some certainty regarding industrial customers' volumes by requiring an annual service election, special charges for changes between elections, and in some cases, a minimum or maximum volume requirement before changing options.

Customer growth rates for natural gas utilities in the Pacific Northwest historically have been among the highest in the nation due to lower market saturation as natural gas became widely available as a residential heating source after other fuel options. We estimate natural gas is in less than 60% of residential single-family dwellings in our service territory. Therefore, growth in the region comes from both new single and multi-family housing construction and existing homes converting to natural gas. Prior to the most recent recession, our customer growth rate averaged over 3% for many years. From 2009 to 2012, growth dipped below 1%, but in 2013 and 2014, the 12-month growth rate

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increased to 1.3% and 1.4%, respectively. Natural gas is a preferred energy resource in our service territory, as it is a low-cost, reliable, clean energy choice, and as such, we believe there is potential for continued growth. See Note 4 for information on the utility's assets and results of operations.

Competitive Conditions
In our service areas, we have no direct competition from other natural gas distributors, but we compete with other forms of energy supply in each customer class. This competition among energy suppliers is based on price, efficiency, reliability, performance, market conditions, technology, federal and state energy policy, and environmental impacts.

For residential and small to mid-size commercial customers, we compete primarily with electricity, fuel oil, propane, and renewable energy providers.

In the industrial and large commercial markets, we compete with all forms of energy, including competition from wholesale natural gas marketers. In addition, large industrial customers could bypass our local gas distribution system by installing their own direct pipeline connection to the interstate pipeline system. We have designed custom transportation service agreements with several of our largest industrial customers to provide transportation service rates that are competitive with the customer’s costs of installing their own pipeline; these agreements generally prohibit bypass. Due to the cost pressures confronting 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 could experience deterioration of margin if customers bypass or switch over to custom contracts with lower profit margins.

Seasonality of Business
Our utility business is seasonal in nature due to higher gas usage by residential and commercial customers during the cold winter heating months.

Regulation and Rates
The utility is subject to regulation by the OPUC, WUTC, and FERC. These regulatory agencies authorize rates and allow recovery mechanisms to provide our utility the opportunity to recover prudently incurred capital and operating costs from customers, while also earning a reasonable return on investment for investors. In addition, the OPUC and WUTC also regulate the system of accounts and issuance of securities by our utility.

We file general rate cases and rate tariff requests periodically with the commissions to establish approved rates, an authorized ROE, an overall rate of return on rate base (ROR), an authorized utility capital structure, and other revenue/cost deferral and recovery mechanisms.

In addition, under our Mist interstate storage certificate with FERC, the utility is required to file either a petition for rate approval or a cost and revenue study every five years to change or justify maintaining the existing rates for the interstate storage service. We filed a rate petition in 2013

and received approval in 2014 for new maximum cost-based rates effective January 1, 2014.

The utility's most recent general rate case in Oregon was effective November 1, 2012, and the latest Washington rate case was effective January 1, 2009. Our current approved rates and recovery mechanisms for each service area include:

	Oregon	Washington(1)
Authorized Rate Structure:		
ROE	9.5%	10.1%
ROR	7.8%	8.4%

Debt/Equity Ratio	50%/50%	49%/51%
Key Regulatory Mechanisms:		
PGA	X	X
Incentive Sharing	X	
Weather Normalization Tariff	X	
Decoupling	X	
SIP	X	
Pension Balancing	X	
Environmental Cost Deferral	X	X
SRRM	X	

(1) Although we do not have the same specific regulatory mechanisms in Washington, we do have approved regulatory deferral orders that allow us to defer certain costs for future recovery through the PGA or future general rate cases, such as our environmental cost deferral order.

In general, these rates and regulatory mechanisms do not allow the utility to earn a profit or incur a loss on our gas commodity purchases. This means gas commodity purchase costs are primarily a pass-through cost in customer rates, with the exception of our original gas reserves investment and incentive cost sharing mechanism in Oregon. Under this mechanism, we can either increase or decrease margin revenues based on higher or lower actual gas purchase costs compared to gas purchase costs embedded in the PGA. Except for as described below, we can earn an authorized return on the equivalent rate base investment on our gas reserves.

For a complete discussion of regulatory matters, open dockets, current regulatory activities, and additional details on each rate mechanism, see Part II, Item 7, "Results of Operations—Regulatory Matters" and "Gas Storage" below.

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Gas Supply

The utility strives to secure sufficient, reliable supplies of natural gas to meet the needs of customers at the lowest reasonable cost, while maintaining price stability and managing gas purchase costs prudently. This is accomplished through a comprehensive strategy focused on the following items:

- Diverse Supply - providing diversity of supply sources;
- Diverse Contracts - maintaining a variety of contract durations and types; and
- Cost Management - employing prudent gas cost management strategies.

Diversity of Supply Sources

We purchase our gas supplies primarily from the Alberta and British Columbia areas of Canada and multiple receipt points in the U.S. Rocky Mountains to protect against regional supply disruptions and to optimize price differentials. For 2014, 66% of our gas supply came from Canada, with the balance primarily coming from the U.S. Rocky Mountain region. We believe gas supplies available in the western United States and Canada are adequate to serve our core utility requirements for the foreseeable future. We continue to evaluate the long-term supply mix based on projections of gas production and pricing in the U.S. Rocky Mountain region as well as other regions in North America; however, we believe the cost of natural gas coming from western Canada and the U.S. Rocky Mountain region will continue to track with broader U.S. market pricing. Additionally, the extraction of shale gas has increased the availability of gas supplies throughout North America for the foreseeable future.

We supplement our firm gas supply purchases with gas withdrawals from gas storage facilities, including underground reservoirs and LNG storage facilities. Storage facilities are generally injected with natural gas during off-peak months during the spring and summer and the gas is withdrawn for use during peak demand months in the winter.

The following table presents the storage facilities available for our utility supply:

	Maximum Daily Deliverability (therms in millions)	Capacity (Bcf)
Gas Storage Facilities:		
Owned Facility:		
Mist, Oregon(1)	2.7	10.0
Contracted Facilities:		
Jackson Prairie, Washington(2)	0.5	1.1
Alberta, Canada(3)	0.5	4.0
LNG Facilities:		
Owned Facilities:		
Newport, Oregon	0.6	0.9
Portland, Oregon	1.2	0.6
Total	5.5	16.6

(1) The Mist gas storage facility has a total maximum daily deliverability of 5.2 million therms and a total working gas capacity of about 16 Bcf, of which 2.7 million therms of daily deliverability and 10 Bcf of storage capacity are reserved for core utility customers.

(2) The storage facility is located near Chehalis, Washington and is contracted from Northwest Pipeline, a subsidiary of The Williams Companies. A portion of the related pipeline transportation service from this facility is subject to curtailment and considered secondary firm capacity. As a result, NW Natural is evaluating the reliability of the capacity as part of the IRP process.

(3) This resource does not add to our total peak day capacity, but helps to manage price risks as it displaces equivalent volumes of heating season spot purchases.

The Mist facility is used for both utility and non-utility purposes. Under our regulatory agreements with the OPUC and WUTC, non-utility gas storage at Mist can be developed in advance of core utility customer needs but is subject to recall by the utility when needed to serve utility customers as their demand increases. In May 2015, the utility plans to recall 0.3 million therms per day of deliverability and 0.7 Bcf of associated storage capacity from the non-utility business to serve core utility customer needs.

In addition, we have the ability to recall pipeline capacity and supply resources from certain customers if needed.

Diverse Contract Durations and Types

We have a diverse portfolio of short-, medium-, and long-term firm gas supply contracts and a variety of contract types including firm and interruptible supplies plus supplemental supplies from gas storage facilities.

Our portfolio of firm gas supply contracts typically includes the following gas purchase contracts: year-round and winter-only baseload supplies; seasonal supply with an option to call on additional daily supplies during the winter heating season; and daily or monthly spot purchases.

During 2014, we purchased a total of 761 million therms under contracts with durations outlined in the chart below:

Contract Duration (primary term)	Percent of Purchases	
Long-term (one year or longer)	30	%
Short-term (more than one month, less than one year)	25	
Spot (one month or less)	45	
Total	100	%

We renew or replace gas supply contracts as they expire. Aside from the gas supplies provided by an independent energy marketing company as part of asset management services, no individual supplier provided over 10% of our gas supply requirements in 2014.

Gas Cost Management Strategy

The cost of gas sold to utility customers primarily consists of the following items, which are included in annual PGA rates: purchase price paid to suppliers; charges paid to pipeline companies to store and transport gas to our distribution system; our gas reserves contract; and gains or losses related to gas commodity derivative contracts.

We employ a number of strategies to mitigate the cost of gas sold to utility customers. Our primary strategies for managing gas commodity price risk include:

- negotiating fixed prices directly with gas suppliers;

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- negotiating financial derivative contracts that: (1) effectively convert floating index prices in physical gas supply contracts to fixed prices (referred to as commodity price swaps); or (2) effectively set a ceiling or floor price, or both, on floating index priced physical supply contracts (referred to as commodity price options such as calls, puts, and collars) See Part II, Item 7A, "Quantitative and Qualitative Disclosures About Market Risk—Credit Risk—Credit Exposure to Financial Derivative Counterparties";
- buying physical gas supplies at a set price and injecting the gas into storage for price stability and to minimize pipeline capacity demand costs; and
- investing in gas reserves for longer term price stability. See Note 11.

We also contract with an independent energy marketing company to capture opportunities regarding our unused storage and pipeline capacity when those assets are not serving the needs of our core utility customers. Our asset management activities provide cost savings that reduce our utility customer's cost of gas and opportunities to generate incremental revenues for NW Natural's shareholders from a regulatory incentive-sharing mechanism, which are included in our gas storage segment.

Transportation of Gas Supplies

Our local gas distribution system is reliant on a single, bi-directional interstate transmission pipeline to bring gas supplies into our distribution system. Although we are dependent on a single pipeline, the pipeline’s gas flows into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from Alberta as well as the U.S. Rocky Mountain supply basins.

We incur monthly demand charges related to our firm pipeline transportation contracts. Our largest pipeline agreements are with Northwest Pipeline. These contracts are multi-year contracts with expirations ranging from 2016 to 2044. We actively work with Northwest Pipeline and others to renew contracts in advance of expiration and ensure gas transportation capacity is sufficient to meet our utility needs.

Rates for interstate pipeline transportation services are established by FERC within the U.S. and by Canadian authorities for services on Canadian pipelines.

As mentioned above, NW Natural's service territory is dependent on a single pipeline for its natural gas supply. Although supply has not been disrupted in the recent past, pipeline replacement projects and long-term projected natural gas demand in our region underscore the need for pipeline transportation diversity. In addition, there are several potential industrial projects in the region, which could increase the demand for natural gas and the need for additional pipeline capacity and pipeline diversity.

Several interstate pipeline projects currently proposed could meet the region's and NW Natural's projected demand. Though only one of these projects will likely be completed with the pipeline location dependent on the location of the

successful project. NW Natural will evaluate and closely monitor the currently prospected projects to determine the best option for ratepayers. The Company also has an equity investment in Trail West Holdings, LLC (TWH) that is developing plans to build the Trail West pipeline, formerly known as Palomar or the cross-Cascades pipeline project. This pipeline would connect TransCanada Pipelines Limited’s (TransCanada) Gas Transmission Northwest (GTN) interstate transmission line to our local gas distribution system. If constructed, this pipeline would provide another transportation path for gas purchases from Alberta and the U.S. Rocky Mountains in addition to the one that currently moves gas through the Northwest Pipeline system. See Part II, Item 7, "2015 Outlook".

Gas Distribution

The goals of our gas distribution operations are:

- Safety - Building and maintaining a safe pipeline distribution system;
- Reliability - Ensuring gas resource portfolios are sufficient to satisfy customer requirements under extreme cold weather conditions;
- Lowest Reasonable Cost - Acquiring gas supplies at the lowest reasonable cost for utility customers;
- Price Stability - Managing commodity price volatility by making the best use of physical assets and financial instruments; and
- Cost Recovery - Managing gas purchase costs prudently to minimize risks associated with regulatory reviews and cost recovery.

These goals are discussed more fully in the following sections.

Safety

Safety and the protection of our employees, our customers and the public at large are, and will remain, our top priorities. We monitor and maintain our pipeline distribution system and storage operations with the goal of ensuring natural gas is stored and delivered safely, reliably and efficiently. Since 2004, we have partnered with the OPUC and WUTC on various efforts to improve the safety and reliability of our distribution system. In Oregon, we have a cost recovery program that integrated the Company’s programs for bare steel replacement, transmission pipeline integrity management, and distribution pipeline integrity management into a single program. Currently, we are seeking renewal of the System Integrity Program (SIP); however, our bare steel replacement program continues in 2015. See Part II, Item 7, "Results of Operations—Regulatory Matters—System Integrity Program".

Natural gas distribution businesses are likely to be subject to even greater federal and state regulation in the future due to recent pipeline incidents involving other companies. Most recently, additional regulations from the U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA) were drafted in 2013 with final regulations expected in 2015 and an effective date in 2016. We will continue to work diligently with industry associations as well as federal and state regulators to ensure the safety of our system and compliance with new laws and regulations. We expect the costs associated with compliance to federal, state, and local rules would be recoverable in rates.

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Reliability

The effectiveness of our gas distribution system ultimately rests on whether we provide reliable service to our core utility customers. To ensure our effectiveness, we develop a composite design year, including a seven day design peak event based on the most severe cold weather experienced during the last 30 years in our service territory.

Our projected maximum design day firm utility customer sendout totals approximately 9.3 million therms. Of this total, we are currently capable of meeting over 50% of our maximum design day requirements with gas from storage located within or adjacent to our service territory, while the remaining supply requirements would be met by gas purchases under firm gas purchase contracts and recall agreements.

On February 6, 2014, we experienced our current record customer sendout of 9.0 million therms, which included 7.4 million firm therms. This record day was approximately 9 degrees Fahrenheit warmer than the design day temperature.

To supplement near-term natural gas supplies, the Company planned to segment transportation capacity during the 2014-2015 heating season for approximately 0.4 million therms per day if needed. Pipeline segmentation is a natural gas transportation mechanism under which a shipper can leverage its firm pipeline transportation capacity by separating it into multiple segments with alternate delivery routes. The reliability of service on these alternate routes will vary depending on the constraints of the pipeline system. For those segments with acceptable reliability, segmentation provides a shipper with increased flexibility and potential cost savings compared to traditional pipeline service.

Specifically, the Company could segment pipeline capacity that flows from Stanfield, Oregon with additional gas expected from the Sumas, Washington trading hub. This segmented capacity is considered reliable as the pipeline has not experienced constraints from Sumas in recent years.

We believe our gas supplies would be sufficient to meet existing firm customer demand if we were to experience maximum design day weather conditions. We will continue to evaluate and update our forecasted requirements and incorporate changes in our integrated resource plan (IRP) process.

The following table shows the sources of supply projected to be used to satisfy the design day sendout for the 2014-2015 winter heating season:

Therms in millions	Therms	Percent	
Sources of utility supply:			
Firm supply purchases	3.3	36	%
Mist underground storage (utility only)	2.7	29	
Company-owned LNG storage	1.8	20	
Off-system storage contract[1]	0.5	5	
Pipeline segmentation capacity	0.4	4	
Recall agreements	0.4	4	
Peak day citygate deliveries[2]	0.2	2	
Total	9.3	100	%

(1) A portion of the related pipeline transportation service from this facility is subject to curtailment and considered secondary firm capacity. As a result, NW Natural is evaluating the reliability of the capacity as part of the IRP process.

(2) These citygate deliveries are contracted from December 2014 to February 2015 with this resource being evaluated for future heating seasons after the current winter.

The OPUC and WUTC have IRP processes in which utilities define different growth scenarios and corresponding resource acquisition strategies in an effort to evaluate supply and demand resource requirements, consider uncertainties in the planning process and the need for flexibility to respond to changes, and establish a plan for providing reliable service at the least cost.

In general, the IRP is filed biannually with both the OPUC and the WUTC. An update is filed in Oregon in the off year. The OPUC acknowledges receipt of the IRP; whereas the WUTC provides notice our IRP met the requirements of the Washington Administrative Code. OPUC acknowledgment of the IRP does not constitute ratemaking approval of any specific resource acquisition strategy or expenditure. However, the Commissioners generally indicate they would give considerable weight in prudence reviews to utility actions consistent with acknowledged plans. The WUTC has indicated the IRP process is one factor it will consider in a prudence review. We filed our 2014 IRP in both Oregon and Washington in August 2014 and received acknowledgment from the OPUC in February 2014. We are currently awaiting notice from the WUTC.

Lowest Reasonable Cost
We apply cost management strategies, including fixed-price contracts, financial derivative instruments, storage supplies, acquisition of gas reserves, and asset management to acquire gas supplies at the lowest reasonable cost for utility customers. See "Gas Supply—Gas Cost Management Strategy" above.

Price Stability
We use physical assets and financial instruments to manage commodity price volatility. We purchase gas for our storage facilities generally during the summer months when demand and gas prices are typically lower. In addition, our gas reserves provide long-term gas price stability for our utility customers. We also mitigate year-to-year commodity price volatility through financial hedge contracts such as commodity price swaps and options.

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Cost Recovery

Mechanisms for gas cost recovery are designed to be fair and reasonable, with an appropriate balance between the interests of our customers and shareholders. In general, utility rates are designed to recover the costs, but not to earn a return on, the gas commodity sold. We minimize risks associated with gas cost recovery by resetting customer rates annually through the PGA and aligning customer and shareholder interests through the use of sharing, weather normalization, and conservation mechanisms in Oregon. See Part II, Item 7, "Results of Operations—Regulatory Matters—Rate Mechanisms" and "Results of Operations—Business Segments—Local Gas Distribution Utility Operations—Cost of Gas."

GAS STORAGE

The gas storage segment includes the following:

- the non-utility portion of the Mist gas storage facility near Mist, Oregon;
- our 75% share of the Gill Ranch gas storage facility near Fresno, California; and
- asset management services provided by an independent energy marketing company.

In general, the supply of natural gas remains relatively stable over the course of a year, while the demand for natural gas typically fluctuates seasonally. Storage facilities allow customers to purchase and inject natural gas supplies during periods of low demand and withdraw these supplies for use or resale during periods of higher demand. These facilities allow us to capitalize on the imbalance of supply and demand and price volatility for natural gas.

In recent years, as a result of the abundant supply of natural gas in North America, we have seen lower, more stable natural gas prices, which have created a challenging gas storage environment particularly in California. The spot price and front end of the forward curve for natural gas temporarily increased in late 2013 and early 2014 due to extreme cold weather. The effect during 2014 was a significant decline in storage levels, which resulted in spring and summer natural gas prices equal to projected gas prices for the winter of 2014-15. Thus, the purchase of spring and summer gas for injection into storage was less desirable and storage values decreased. While we are seeing some improvement in storage values coming out of this year's warmer than normal winter, overall prices remain lower than our long-term contracts that expired during the 2013-14 gas storage year. Despite current market conditions, we continue to believe in the long-term need for gas storage, particularly in California, due to various regulations including renewable portfolio standards and signs of economic recovery and industrial growth in the region. Increased demand for natural gas and/or decreased drilling activity could change the current supply/demand imbalance and result in higher gas prices or increased market volatility, which could position this segment for growth.

See Note 4 for more information on gas storage assets and results of operations and "Financial Condition—Liquidity and Capital Resources".

Gas Storage Facilities

The following table provides information concerning the Company’s non-utility gas storage facilities:

	Designed Storage Capacity (Bcf)	Maximum Deliverability (Therms in millions/day)[3]	Injection (Therms in millions/day)[3]
Mist Storage[1]	6	2.4	1.0
Gill Ranch Storage[2]	15	4.9	2.4

(1) Approximately 6 Bcf of a total 16 Bcf at Mist is currently available to our gas storage segment. The remaining 10 Bcf is used to provide gas storage for our local distribution business and its utility customers. All storage capacity and daily deliverability currently developed for the gas storage segment at Mist is available for recall by the utility. In May 2015, the utility plans to recall approximately 0.3 million therms per day of deliverability or 0.7 Bcf of

capacity for core utility customer use.

(2) Our share of the Gill Ranch facility is currently 15 Bcf out of a total capacity of 20 Bcf.

(3) Our share of the expected daily maximum injection and deliverability rates.

Mist Storage Facility

The Mist storage facility began operations in 1989 and currently consists of seven depleted natural gas reservoirs, 22 injection and withdrawal wells, a compressor station, dehydration and control equipment, gathering lines and other related facilities.

SERVICES. Mist provides multi-cycle gas storage services to customers in the interstate and intrastate markets from the facility located in Columbia County, Oregon, near the town of Mist. The Mist field was converted to storage operations for our utility customers. Since 2001, gas storage capacity at Mist has also been made available to interstate customers by developing new incremental capacity in advance of core utility customer requirements to meet the demands for interstate storage service. These interstate storage services are offered under a limited jurisdiction blanket certificate issued by FERC. In addition, since 2005 we have offered intrastate firm storage services in Oregon under an OPUC-approved rate schedule as an optional service to eligible non-residential utility customers.

CUSTOMERS. For Mist interstate storage services, firm service agreements with customers are entered into with terms typically ranging from 1 to 10 years. Currently, our gas storage revenues from Mist are derived primarily from firm service customers who provide energy related services, including natural gas production or distribution, electric generation, and energy marketing. Three storage customers currently account for over 90% of our existing non-utility gas storage capacity at Mist, with the largest customer accounting for about half of the total capacity. These three customers have contracts that expire at various dates through 2018.

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

SEASONALITY. Mist gas storage revenues generally do not follow seasonal patterns similar to those experienced by the utility because most of the storage capacity is contracted with customers for firm service, which are primarily in the form of fixed monthly reservation charges and are not affected by customer usage. However, there is seasonal variation with Mist storage capacity related to utility customers' lower demand during the spring and summer months. This surplus storage capacity and related transportation capacity can be optimized under regulatory sharing agreements with the OPUC and WUTC. See "Asset Management" below.

REGULATION. Our Mist facility is subject to regulation by the OPUC and WUTC. In addition, FERC has approved maximum cost-based rates under our Mist interstate storage certificate. We are required to file either a petition for rate approval or a cost and revenue study with FERC at least every five years to change or justify maintaining the existing rates for the interstate storage service. See Part II, Item 7, "Results of Operations—Regulatory Matters".

EXPANSION OPPORTUNITIES. The need for new, flexible gas-fired generation has been identified in the Pacific Northwest region to integrate intermittent wind resources into the power system, thereby increasing the associated need for gas storage. To address this need, we are planning a potential expansion of our Mist storage facility. If completed, this expansion would be supported by a contract with Portland General Electric (PGE) to serve gas-fired electric power generation facilities at Port Westward, Oregon, which is located approximately 15 miles from Mist.

The project would include a new reservoir providing up to 2.5 Bcf of available storage, an additional compressor station with design capacity of 120,000 dekatherms of gas per day, and a 13-mile pipeline to connect to PGE’s gas plants at Port Westward. The current estimated cost of the expansion is approximately $125 million with a potential in-service date in 2018 or 2019, depending on the permitting process and construction schedule.

In early 2015, we received authorization from PGE to begin permitting and land acquisition work, and in October 2014 a new rate schedule was approved under which we will provide no-notice gas storage service associated with the expansion. This expansion project is subject to PGE's final approval of project costs and a notice to proceed, as well as the receipt of permits, certain land rights, and other conditions.

Gill Ranch Facility

Gill Ranch Storage, LLC (Gill Ranch), our subsidiary, has a joint project agreement with Pacific Gas and Electric Company (PG&E) to develop and own the Gill Ranch underground natural gas storage facility near Fresno, California. Currently, Gill Ranch is the sole operator of the facility. The facility began operations in 2010 and consists of three depleted natural gas reservoirs, 12 injection and withdrawal wells, a compressor station, dehydration and control equipment, gathering lines, an electric substation, a

natural gas transmission pipeline extending 27 miles from the storage field to an interconnection with the PG&E transmission system, and other related facilities. Gill Ranch owns the rights to 75% of the available storage capacity at the facility. Gill Ranch’s share of the facility currently provides 15 Bcf of working gas capacity.

California has been impacted by challenging market conditions for gas storage, with contract prices in the region at historic lows for the past two years and a greater number of competitors in the area compared to the Pacific Northwest region. More recently, we have seen improvement in pricing for the upcoming 2015-2016 gas storage year, however prices are still lower than our long-term contracts that expired during the 2013-2014 gas storage year. We are committed to using a variety of contracting tools to maximize the value of the Gill Ranch facility. In the longer term, we anticipate a rebound in gas storage values driven by a variety of factors including changes in energy generation triggered by California's renewable portfolio standards and carbon reduction targets, recovery of the California economy, and other favorable market conditions in and around California. We believe these factors could increase demand for natural gas storage and increase price volatility.

SERVICES. Gill Ranch provides intrastate, multi-cycle storage services in California at market-based rates under a CPUC-approved tariff that includes firm storage service, interruptible storage service, and park and loan storage services. Our Gill Ranch facility is not currently authorized to provide interstate gas storage services.

CUSTOMERS. Customer contracts for firm storage capacity at Gill Ranch are as long as 28 years in duration; however, the majority of the contracted capacity is shorter term in nature due to market conditions. In the near-term, we expect Gill Ranch to contract for terms mostly ranging from one to five years. For the 2014-15 gas storage year, Gill Ranch has several storage customers, with the largest single contract accounting for approximately 13% of our storage capacity. In the near term, we continue to expect shorter contract lengths reflecting current market prices and trends.

The California market served by Gill Ranch is larger, and has a greater diversity of prospective customers, than the Pacific Northwest market served by Mist. Therefore, we expect less sensitivity to any single customer or group of customers at Gill Ranch. Current Gill Ranch customers provide energy related services, including natural gas production, marketing, and electric generation.

COMPETITIVE CONDITIONS. The Gill Ranch storage facility competes with a number of other storage providers, including local integrated gas companies and other independent storage operators in the northern California market. As storage markets recover, there could also be expansions and proposed new construction of storage capacity in northern California that may create increased competition.

SEASONALITY. Although we expect much of the storage revenue at Gill Ranch to be in the form of fixed monthly demand charges, cash flows can fluctuate due to timing of asset management and other revenues. In addition, a significant portion of operating costs at Gill Ranch are subject to seasonality based on periods when storage customers elect to inject or withdraw.

REGULATION. Gill Ranch has a tariff on file with the CPUC authorizing it to charge market-based rates for the storage services offered. See Part II, Item 7, "Results of Operations–Regulatory Matters".

EXPANSION OPPORTUNITIES. Subject to market demand, project execution, available financing, receipt of future permits, and other rights, the Gill Ranch storage facility can be expanded beyond the current combined permitted capacity of 20 Bcf without further expansion of the takeaway pipeline system. Taking these considerations into account and with certain infrastructure modifications, we currently estimate the Gill Ranch storage facility could support an additional 25 Bcf of storage capacity, bringing the total storage capacity to approximately 45 Bcf, of which our current rights would give us up to an additional 7.5 Bcf or ownership of a total of approximately 22.5 Bcf.

Asset Management

We contract with an independent energy marketing company to provide asset management services, primarily through the use of commodity and pipeline capacity release transactions. The results are included in the gas storage segment, except for amounts allocated to our utility pursuant to regulatory sharing agreements involving the use of utility assets. Utility pre-tax income from third-party asset management services is subject to revenue sharing with core utility customers. See Part II, Item 7, "Results of Operations—Business Segments—Gas Storage".

OTHER

We have non-utility investments and other business activities which are aggregated and reported as other. Other primarily consists of:

- an equity method investment in a joint venture to build and operate a gas transmission pipeline in Oregon. Trail West Holdings, LLC (TWH) is owned 50% by NWN Energy, a wholly-owned subsidiary of NW Natural, and 50% by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation. See Part II, Item 7, "2015 Outlook";
- a minority interest in Kelso-Beaver Pipeline held by our wholly-owned subsidiary NNG Financial Corporation (NNG Financial); and
- other operating and non-operating income and expenses of the parent company that are not included in utility or gas storage operations.

The pipelines referred to above are regulated by FERC. Less than 1% of our consolidated assets and consolidated net income are related to activities in other. See Note 4 for summary information for these assets and results of operations.

ENVIRONMENTAL ISSUES

Properties and Facilities

We own, or previously owned, properties and facilities that are currently being investigated that may require environmental remediation and are subject to federal, state and local laws and regulations related to environmental matters. These laws and regulations may require expenditures over a long timeframe to address certain environmental impacts. Estimates of liabilities for environmental costs are difficult to determine with precision because of the various factors that can affect their ultimate disposition.

These factors include, but are not limited to, the following:

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

We seek recovery of environmental costs through insurance and customer rates, and we believe recovery of these costs is probable. At December 31, 2014, we had an open proceeding with the OPUC to address implementation issues for the SRRM, which allows for regulatory cost recovery of our environmental expenditures. In February 2015, the OPUC issued an order addressing outstanding items related to the SRRM, including prudence of past costs, an earnings test, and a regulatory disallowance of $15 million pre-tax to be recorded in the first quarter of 2015 in accordance with accounting guidance and our regulatory accounting policy. See "Results of Operations—Rate Matters—Rate Mechanisms—Environmental Costs" below, Note 2, Note 15, and Note 16.

Greenhouse Gas Issues

We recognize our businesses are likely to be impacted by future requirements to address greenhouse gas emissions. Future federal and/or state requirements may seek to limit future emissions of greenhouse gases, including both carbon dioxide (CO_2) and methane. These future laws and regulations may require certain activities to reduce emissions and/or increase the price paid for energy based on its carbon content.

Current federal rules require the reporting of greenhouse gas emissions. In September 2009, the EPA issued a final rule requiring the annual reporting of greenhouse gas emissions from certain industries, specified large greenhouse gas emission sources, and facilities that emit 25,000 metric tons or more of CO_2 equivalents per year. We began reporting emission information in 2011. Under this reporting rule, local gas distribution companies like NW Natural are required to report system throughput to the EPA on an annual basis. The EPA also issued additional

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greenhouse gas reporting regulations requiring the annual reporting of fugitive emissions from our operations.

The outcome of federal and state policy development in the area of climate change cannot be determined at this time, but these initiatives could produce a number of results including new regulations, legal actions, additional charges to fund energy efficiency activities, or other regulatory actions. The adoption and implementation of any regulations limiting emissions of greenhouse gas from our operations could require us to incur costs to reduce emissions of greenhouse gases associated with our operations, which could result in an increase in the prices we charge our customers or a decline in the demand for natural gas. On the other hand, because natural gas is a fossil fuel with relatively low carbon content, it is also possible future carbon constraints could create additional demand for natural gas for electric generation, direct use of natural gas in homes and businesses, and as a reliable and relatively low-emission back-up fuel source for alternative energy sources. Requirements to reduce greenhouse gas emissions from the transportation sector, such as those in Oregon's clean fuel standard, could also result in additional demand for natural gas for use in vehicles.

We continue to take steps to address future greenhouse gas emission issues, including actively participating in policy development through participation on various Oregon taskforces and, at the federal level, within the American Gas Association. We engage in policy development and in identifying ways to reduce greenhouse gas emissions associated with our operations and our customers' gas use, including offering the Smart Energy program, which allows customers to voluntarily contribute funds to projects such as biodigesters on dairy farms that offset the greenhouse gases produced from their natural gas use.

EMPLOYEES

At December 31, 2014, the utility workforce consisted of 612 members of the Office and Professional Employees International Union (OPEIU) Local No. 11, AFL-CIO, and 472 non-union employees. Our labor agreement with members of OPEIU covers wages, benefits and working conditions. On May 22, 2014, our union employees ratified a new labor agreement (Joint Accord) that extends to November 30, 2019, and thereafter from year to year unless either party serves notice of its intent to negotiate modifications to the collective bargaining agreement.

At December 31, 2014, our subsidiaries had a combined workforce of 19 non-union employees. Our subsidiaries receive certain services from centralized operations at the utility, and the utility is reimbursed for those services pursuant to a Shared Services Agreement.

ADDITIONS TO INFRASTRUCTURE

We make capital expenditures in order to maintain and enhance the safety and integrity of our pipelines, gate stations, storage facilities and related assets, to expand the reach or capacity of those assets, or improve the efficiency of our operations. We expect to make a significant level of capital expenditures for additions to utility and gas storage infrastructure over the next five years, reflecting continued

investments in customer growth, technology, and distribution system improvements. For the five-year period ending in 2019, capital expenditures for the utility are estimated to be between $850 and $950 million, including the Company's proposed investment in an expansion of our Mist gas storage facility.

In 2015, utility capital expenditures are estimated to be between $140 and $150 million, and non-utility capital investments are estimated to be less than $10 million. Additional spend for gas storage and other investments during and after 2015 will depend largely on future decisions about potential expansion opportunities in gas storage projects.

EXECUTIVE OFFICERS OF THE REGISTRANT

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

AVAILABLE INFORMATION

We file annual, quarterly and special reports and other information with the Securities and Exchange Commission (SEC). Reports, proxy statements and other information filed by us can be read and requested through the SEC by mail at U.S. Securities and Exchange Commission, Office of FOIA/PA Operations, 100 F Street, N.E., Washington, D.C. 20549, by facsimile at (202) 772-9337, or online at its website (http://www.sec.gov). You can obtain information about access to the Public Reference Room and how to access or request records by calling the SEC at (202) 551-8090. The SEC website contains reports, proxy and information statements and other information we file electronically. In addition, we make available on our website (http://www.nwnatural.com), our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) and proxy materials filed under Section 14 of the Securities Exchange Act of 1934, as amended (Exchange Act), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC.

We have adopted a Code of Ethics for all employees and officers that is available on our website. We intend to disclose amendments to, and any waivers from the Code of Ethics on our website. Our Corporate Governance Standards, Director Independence Standards, charters of each of the committees of the Board of Directors and additional information about the Company are also available at the website. Copies of these documents may be requested, at no cost, by writing or calling Shareholder Services, NW Natural, One Pacific Square, 220 N.W. Second Avenue, Portland, Oregon 97209, telephone 503-226-4211 ext. 2402.

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ITEM 1A. RISK FACTORS

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

Risks Related to our Business Generally

REGULATORY RISK. Regulation of our businesses, including changes in the regulatory environment, failure of regulatory authorities to approve rates which provide for timely recovery of our costs and an adequate return on invested capital, or an unfavorable outcome in regulatory proceedings may adversely impact our financial condition and results of operations.

The OPUC and WUTC have general regulatory authority over our utility business in Oregon and Washington, respectively, including the rates charged to customers, authorized rates of return on rate base, including ROE, the amounts and types of securities we may issue, services we provide and the manner in which we provide them, the nature of investments we make, actions investors may take with respect to our company, and deferral and recovery of various expenses, including, but not limited to, pipeline replacement, environmental remediation costs, pension expense, transactions with affiliated interests, and other matters. Similarly, in our gas storage businesses FERC has regulatory authority over interstate storage services, the CPUC has regulatory authority over our Gill Ranch storage operations, and the WUTC and OPUC have regulatory over our Mist storage operations.

The prices the OPUC and WUTC allow us to charge for retail service, and the maximum FERC-approved rates FERC authorizes us to charge for interstate storage and related transportation services, are the most significant factors affecting our financial position, results of operations and liquidity. The OPUC and WUTC have the authority to disallow recovery of costs they find imprudently incurred or otherwise disallow. For example, in the most recent OPUC order issued to the Company regarding implementation of our SRRM, the OPUC disallowed from rate recovery approximately $15 million of approximately $95 million of our total environmental expenditures made from 2003 to 2012, due to the OPUC's application of a recently formulated earnings test. Additionally, the rates allowed by the FERC may be insufficient for recovery of costs incurred. We expect to continue to make expenditures to expand, improve and operate our utility distribution and gas storage systems. Regulators can find such expansions or improvements of expenditures were not prudently incurred, and deny recovery. Additionally, while the OPUC and WUTC have established an authorized rate of return for our utility through the ratemaking process, the regulatory process does not provide assurance that we will be able to achieve the earnings level authorized.

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

In our latest general rate case with the OPUC, various items were deferred for future resolution in separate proceedings, including recovery of prepaid pension costs, and our revenue-sharing arrangement on the utility's interstate storage activities. The regulatory proceedings in which these issues will be resolved typically involve multiple parties, including governmental agencies, consumer advocacy groups, and other third parties. Each party has differing concerns, but all generally have the common objective of limiting amounts included in rates. We cannot predict the timing or outcome of these deferred proceedings or the effects of those outcomes on our results of operations and financial condition.

ENVIRONMENTAL LIABILITY RISK. Certain of our properties and facilities may pose environmental risks requiring remediation, the costs of which are difficult to estimate and which could adversely affect our financial condition, results of operations, and cash flows.

We own, or previously owned, properties that require environmental remediation or other action. We accrue all material loss contingencies relating to these properties. A regulatory asset at the utility has already been recorded for estimated costs pursuant to a deferral order from the OPUC and WUTC. In addition to maintaining regulatory deferrals, we settled with most of our historical liability insurers for only a portion of the costs we have incurred to date and expect to incur in the future. To the extent amounts we recovered from insurance are inadequate or we are unable to recover these deferred costs in utility customer rates, we would be required to reduce our regulatory asset which would result in a charge to current year earnings. In addition, in our most recent Oregon general rate case, the OPUC approved the SRRM, which limits recovery of our deferred amounts to those amounts which satisfy an annual prudence review and a recently adopted earnings test that requires the Company to contribute additional amounts toward environmental remediation costs above approximately $10 million in years in which the Company earns above its authorized Return on Equity (ROE). To the extent the Company earns more than its authorized ROE in a year, the Company would be required to cover environmental expenses greater than the $10 million with those earnings that exceed its authorized ROE. These ongoing prudence reviews and the earnings test could reduce the amounts we are allowed to recover, and could adversely affect our financial condition, results of operations and cash flows.

In addition, we may have disputes with regulators and other parties as to the severity of particular environmental matters and what remediation efforts are appropriate. We cannot predict with certainty the amount or timing of future expenditures related to environmental investigation, remediation or other action, or disputes or litigation arising in relation thereto. Our liability estimates are based on current remediation technology, industry experience gained at similar sites, an assessment of the probable level of involvement, and financial condition of other potentially responsible parties. However, it is difficult to estimate such costs due to uncertainties surrounding the course of environmental remediation, the preliminary nature of certain of our site investigations, and the application of environmental laws that impose joint and several liabilities on all potentially responsible parties. These uncertainties and disputes arising therefrom could lead to further adversarial administrative proceedings or litigation, with associated costs and uncertain outcomes, all of which could adversely affect our financial condition, results of operations and cash flows.

ENVIRONMENTAL REGULATION COMPLIANCE RISK. We are subject to environmental regulations for our ongoing operations, compliance with which could adversely affect our operations or financial results.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to protection of the environment, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, groundwater quality and availability, plant and wildlife protection, and other aspects of environmental regulation. Current and additional environmental regulations could result in increased compliance costs or additional operating restrictions and could have an adverse effect on our financial condition and results of operations, particularly if those costs are not fully recoverable from insurance or through utility customer rates.

GLOBAL CLIMATE CHANGE RISK. Future legislation to address global climate change may expose us to regulatory and financial risk. Additionally, our business may be subject to physical risks associated with climate change, all of which could adversely affect our financial condition, results of operations and cash flows.

There are a number of international, federal and state legislative and regulatory initiatives being proposed and adopted in an attempt to measure, control or limit the effects of global warming and overall climate change, including greenhouse gas emissions such as carbon dioxide and methane. Such current or future legislation or regulation could impose on us operational requirements, additional charges to fund energy efficiency initiatives, or levy a tax based on carbon content. Such initiatives could result in us incurring additional costs to comply with the imposed restrictions, provide a cost advantage to energy sources other than natural gas, reduce demand for natural gas, impose costs or restrictions on end users of natural gas, impact the prices we charge our customers, impose increased costs on us associated with the adoption of new infrastructure and technology to respond to such requirements, and may impact cultural perception of our service or products negatively, diminishing the value of our brand, all of which could adversely affect our business practices, financial condition and results of operations.

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

These and other physical changes could result in disruptions to natural gas production and transportation systems potentially increasing the cost of gas beyond that assumed in our PGA and affecting our ability to procure gas to meet our customer demand. These changes could also affect our distribution systems resulting in increased maintenance and capital costs, disruption of service, regulatory actions and lower customer satisfaction. Additionally, to the extent that climate change adversely impacts the economic health or weather conditions of our service territory directly, it could adversely impact customer demand or our customers' ability to pay. Such physical risks could have an adverse effect on our financial condition, results of operations, and cash flows.

BUSINESS DEVELOPMENT RISK. Our business development projects may encounter unanticipated obstacles, costs, changes or delays that could result in a project becoming impaired, which could negatively impact our financial condition, results of operations and cash flows.

Business development projects involve many risks. We are currently engaged in several business development projects, including, but not limited to, the early planning and development stages for a regional pipeline in Oregon, and a potential expansion of our gas storage facility at Mist. We may also engage in other business development projects such as investment in additional long-term gas reserves or CNG refueling stations. These projects may not be successful. Additionally, we may not be able to obtain required governmental permits and approvals to complete our projects in a cost-efficient or timely manner potentially resulting in delays or abandonment of the projects. We could also experience startup and construction delays, construction cost overruns, inability to negotiate acceptable agreements such as rights-of-way, easements, construction, gas supply or other material contracts, changes in customer demand or commitment, public opposition to projects, changes in market prices, and operating cost increases. Additionally, we may be unable to finance our business development projects at acceptable interest rates or within a scheduled time frame necessary for completing the project. One or more of these events could result in the project becoming impaired, and such impairment could have an adverse effect on our financial condition and results of operations.

JOINT PARTNER RISK. Investing in business development projects through partnerships, joint ventures or other business arrangements affects our ability to manage certain risks and could adversely impact our financial condition, results of operations and cash flows.

We use joint ventures and other business arrangements to manage and diversify the risks of certain utility and non-

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utility development projects, including our Trail West pipeline, Gill Ranch storage and our gas reserves agreements. We may acquire or develop part-ownership interests in other similar projects in the future. Under these arrangements, we may not be able to fully direct the management and policies of the business relationships, and other participants in those relationships may take action contrary to our interests including making operational decisions that could affect our costs and liabilities. In addition, other participants may withdraw from the project, divest important assets, become financially distressed or bankrupt, or have economic or other business interests or goals that are inconsistent with ours.

For example, our gas reserves arrangements, which operate as a hedge backed by physical gas supplies, involve a number of risks. These risks include gas production that is significantly less than the expected volumes, or no gas volumes; operating costs that are higher than expected; changes in our consolidated tax position or tax law that could affect our ability to take, or timing of, certain tax benefits that impact the financial outcome of this transaction; inherent risks of gas production, including disruption to operations or complete shut-in of the field; and a participant in one of these business arrangements acting contrary to our interests. In addition, while the cost of the original gas reserves venture is currently included in customer rates, the occurrence of one or more of these risks, could affect our ability to recover this hedge in rates. Further, our amended gas reserves arrangement has not been approved for inclusion in rates, and our regulators may ultimately determine to not include all or a portion of that transaction in rates. The realization of any of these situations could adversely impact the project as well as our financial condition, results of operations and cash flows.

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

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

- earthquakes, floods, storms, landslides and other adverse weather conditions and hazards;
- leaks or other losses of natural gas or other hydrocarbons as a result of the malfunction of equipment or facilities;
- damages from third parties, including construction, farm and utility equipment or other surface users;
- operator errors;
- negative performance by our storage reservoirs that could cause us to fail to meet expected or forecasted operational levels or contractual commitments to our customers;
- problems maintaining, or the malfunction of, pipelines, wellbores and related equipment and facilities that form a part of the infrastructure that is critical to the operation of our gas distribution and storage facilities;
- collapse of underground storage caverns;
- migration of natural gas through faults in the rock or to some area of the reservoir where existing wells cannot drain the gas effectively resulting in loss of the gas;
- blowouts (uncontrolled escapes of gas from a pipeline or well) or other accidents, fires and explosions; and
- risks and hazards inherent in the drilling operations associated with the development of the gas storage facilities and/or wells.

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

BUSINESS CONTINUITY RISK. We may be adversely impacted by local or national disasters, pandemic illness, terrorist activities, including cyber attacks, and other extreme events to which we may not able to promptly respond.

Local or national disasters, pandemic illness, terrorist activities, including cyber attacks, and other extreme events are a threat to our assets and operations. Companies in our industry may face a heightened risk due to exposure to acts of terrorism, including physical and security breaches of our information technology infrastructure in the form of cyber attacks. These attacks could target or impact our technology or mechanical systems that operate our natural gas distribution, transmission or storage facilities and result in a disruption in our operations, damage to our system and inability to meet customer requirements. In addition, the threat of terrorist activities could lead to increased economic instability and volatility in the price of natural gas that could affect our operations. Threatened or actual national disasters or terrorist activities may also disrupt capital markets and our ability to raise capital, or impact our suppliers or our customers directly. Local disaster or pandemic illness could result in part of our workforce being unable to operate or maintain our infrastructure or perform other tasks necessary to conduct our business. A slow or inadequate response to events may have an adverse impact on operations and earnings. We may not be able to obtain sufficient insurance to cover all risks associated with local and national disasters, pandemic illness, terrorist activities and other events. Additionally, large scale natural disasters or terrorist attacks could destabilize the insurance industry making insurance we do have unavailable, which could increase the risk that an event could adversely affect our operations or financial results.

EMPLOYEE BENEFIT RISK. The cost of providing pension and postretirement healthcare benefits is subject to changes

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in pension assets and liabilities, changing employee demographics and changing actuarial assumptions, which may have an adverse effect on our financial condition, results of operations and cash flows.

Until we closed the plans to new hires, which for non-union employees was in 2006 and for union employees was in 2009, we provided pension plans and postretirement healthcare benefits to eligible full-time utility employees and retirees. Most of our current utility employees were hired prior to these dates, and therefore remain eligible for these plans. Our cost of providing such benefits is subject to changes in the market value of our pension assets, changes in employee demographics including longer life expectancies, increases in healthcare costs, current and future legislative changes, and various actuarial calculations and assumptions. The actuarial assumptions used to calculate our future pension and postretirement healthcare expense may differ materially from actual results due to significant market fluctuations and changing withdrawal rates, wage rates, interest rates and other factors. These differences may result in an adverse impact on the amount of pension contributions, pension expense or other postretirement benefit costs recorded in future periods. Sustained declines in equity markets and reductions in bond rates may have a material adverse effect on the value of our pension fund assets and liabilities. In these circumstances, we may be required to recognize increased contributions and pension expense earlier than we had planned to the extent that the value of pension assets is less than the total anticipated liability under the plans, which could have a negative impact on financial condition, results of operations and cash flows.

WORKFORCE RISK. Our business is heavily dependent on being able to attract and retain qualified employees and maintain a competitive cost structure with market-based salaries and employee benefits, and workforce disruptions could adversely affect our operations and results.

Our ability to implement our business strategy and serve our customers is dependent upon our continuing ability to attract and retain talented professionals and a technically skilled workforce, and being able to transfer the knowledge and expertise of our workforce to new employees as our largely older workforce retires. We expect that a significant portion of our workforce will retire within the current decade, which will required that we attract, train and retain skilled workers to prevent loss of institutional knowledge or skills gap. Without an appropriately skilled workforce, our ability to provide quality service and meet our regulatory requirements will be challenged and this could negatively impact our earnings. Additionally, within our utility segment a majority of our workers are represented by the OPEIU Local No.11 AFL-CIO (the Union), and are covered by a collective bargaining agreement that extends to November 30, 2019. Disputes with the Union over terms and conditions of the agreement could result in instability in our labor relationship and work stoppages that could impact the timely delivery of gas and other services from our utility and Mist gas storage, which could strain relationships with customers and state regulators and cause a loss of revenues. Our collective bargaining agreement may also limit our flexibility in dealing with our workforce, and our ability to change work rules and practices and implement other efficiency-related

improvements to successfully compete in today’s challenging marketplace, which may negatively affect our financial condition and results of operations.

LEGISLATIVE, COMPLIANCE AND TAXING AUTHORITY RISK. We are subject to governmental regulation, and compliance with local, state and federal requirements, including taxing requirements, and unforeseen changes in or interpretations of such requirements could affect our financial condition and results of operations.

We are subject to regulation by federal, state and local governmental authorities. We are required to comply with a variety of laws and regulations and to obtain authorizations, permits, approvals and certificates from governmental agencies in various aspects of our business. We cannot predict with certainty the impact of any future revisions or changes in interpretations of existing regulations or the adoption of new laws and regulations applicable to them. Additionally, any failure to comply with existing or new laws and regulations could result in fines, penalties or injunctive measures that could affect operating assets. For example, under the Energy Policy Act of 2005, the FERC has civil authority under the Natural Gas Act to impose penalties for current violations of up to $1 million per day for each violation. In addition, as the regulatory environment for our industry increases in complexity, the risk of inadvertent noncompliance may also increase. Changes in regulations, the imposition of additional regulations, and the failure to comply with laws and regulations could negatively influence our operating environment and results of operations.

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

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

The safety and protection of the public, our customers and our employees is and will remain our top priority. We are committed to consistently monitoring and maintaining our distribution system and storage operations to ensure that natural gas is acquired, stored and delivered safely, reliably and efficiently. Given recent high-profile natural gas explosions and accidents in other parts of the country, we anticipate that the natural gas industry may be the subject of even greater federal, state and local regulatory oversight. We intend to work diligently with industry associations and federal and state regulators to ensure compliance with the new laws. We expect there to be increased costs associated with compliance, and those costs could be significant. If these costs are not recoverable in our customer rates, they could have a negative impact on our operating costs and financial results.

HEDGING RISK. Our risk management policies and hedging activities cannot eliminate the risk of commodity price movements and other financial market risks, and our hedging activities may expose us to additional liabilities for which rate recovery may be disallowed, which could result in an adverse impact on our operating revenues, costs, derivative assets and liabilities and operating cash flows.

Our gas purchasing requirements expose us to risks of commodity price movements, while our use of debt and equity financing exposes us to interest rate, liquidity and other financial market risks. In our Utility segment, we attempt to manage these exposures with both financial and physical hedging mechanisms, including our gas reserves transactions which are hedges backed by physical gas supplies. While we have risk management procedures for hedging in place, they may not always work as planned and cannot entirely eliminate the risks associated with hedging. Additionally, our hedging activities may cause us to incur additional expenses to obtain the hedge. We do not hedge our entire interest rate or commodity cost exposure, and the unhedged exposure will vary over time. Gains or losses experienced through hedging activities, including carrying costs, generally flow through the PGA mechanism or are recovered in future general rate cases. However, the hedge transactions we enter into for the utility are subject to a prudence review by the OPUC and WUTC, and, if found imprudent, those expenses may be, and have been previously, disallowed, which could have an adverse effect on our financial condition and results of operations.

In addition, our actual business requirements and available resources may vary from forecasts, which are used as the basis for our hedging decisions, and could cause our exposure to be more or less than we anticipated. Moreover, if our derivative instruments and hedging transactions do not qualify for hedge accounting under generally accepted accounting standards, our hedges may not be effective and our results of operations and financial condition could be adversely affected.

We also have credit-related exposure to derivative counterparties. In general, we require our counterparties to have an investment-grade credit rating at the time the derivative instrument is entered into, and we specify limits on the contract amount and duration based on each counterparty’s credit rating. Nevertheless, counterparties owing us money or physical natural gas commodities could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements to meet our normal business requirements. In that event, our financial results could be adversely affected. Additionally, under most of our hedging arrangements, any downgrade of our senior unsecured long-term debt credit rating could allow our counterparties to require us to post cash, a letter of credit or other form of collateral, which would expose us to additional costs and may trigger significant increases in borrowing from our credit facilities if the credit rating downgrade is below investment grade. Further, based on current interpretations, we are not considered a "swap dealer" or "major swap participant" in 2014, so we are exempt from certain requirements under the Dodd-Frank Act. If we are unable to claim this exemption, we could be subject to higher costs for our derivatives activities.

INABILITY TO ACCESS CAPITAL MARKET RISK. Our inability to access capital, or significant increases in the cost of capital, could adversely affect our financial condition and results of operations.

Our ability to obtain adequate and cost effective short-term and long-term financing depends on maintaining investment grade credit ratings as well as the existence of liquid and stable financial markets. Our businesses rely on access to capital markets, including commercial paper, bond and equity markets, to finance our operations, construction expenditures and other business requirements, and to refund maturing debt that cannot be funded entirely by internal cash flows. Disruptions in capital markets could adversely affect our ability to access short-term and long-term financing. Our access to funds under committed short-term credit facilities, which are currently provided by a number of banks, is dependent on the ability of the participating banks to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Disruptions in the bank or capital financing markets as a result of economic uncertainty, changing or increased regulation of the financial sector, or failure of major financial institutions could adversely affect our access to capital and negatively impact our ability to run our business and make strategic investments.

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

Risks Related Primarily to Our Local Utility Business

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

The cost of natural gas is affected by a variety of factors, including weather, changes in demand, the level of production and availability of natural gas supplies, transportation constraints, availability and cost of pipeline capacity, federal and state energy and environmental regulation and legislation, natural disasters and other catastrophic events, national and worldwide economic and political conditions, and the price and availability of alternative fuels. In our utility segment, the cost we pay for natural gas is generally passed through to our customers through an annual PGA rate adjustment. If gas prices were to increase significantly, it would raise the cost of energy to

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our utility customers, potentially causing those customers to conserve or switch to alternate sources of energy. Significant price increases could also cause new home builders and commercial developers to select alternative fuel sources. Decreases in the volume of gas we sell could reduce our earnings, and a decline in customers could slow growth in our future earnings. Additionally, because a portion of any 10% or 20% difference between the estimated average PGA gas cost in rates and the actual average gas cost incurred is recognized as current income or expense, higher average gas costs than those assumed in setting rates can adversely affect our operating cash flows, liquidity and results of operations. Additionally, notwithstanding our current rate structure, higher gas costs could result in increased pressure on the OPUC or the WUTC to seek other means to reduce rates, which also could adversely affect our results of operations and cash flows.

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

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

Our utility margins and earnings growth have largely depended upon the sustained growth of our residential and commercial customer base due, in part, to the new construction housing market, conversions of customers to natural gas from other fuel sources and growing commercial use of natural gas. Insufficient growth in these markets, for economic, political or other reasons could result in an adverse long-term impact on our utility margin, earnings and cash flows.

RISK OF COMPETITION. Our gas distribution business is subject to increased competition which could negatively affect our results of operations.

In the residential and commercial markets, our gas distribution business competes primarily with suppliers of electricity, fuel oil, propane, and renewable energy. In the industrial market, we compete with suppliers of all forms of energy. Competition among these forms of energy is based on price, efficiency, reliability, performance, market conditions, technology, environmental impacts and public perception.

Technological improvements in other energy sources such as heat pumps could also erode our competitive advantage. If natural gas prices rise relative to other energy sources, or if the cost, environmental impact or public perception of such other energy sources improves relative to natural gas, it may negatively affect our ability to attract new customers or retain our existing residential, commercial and industrial

customers, which could have a negative impact on our customer growth rate and results of operations.

RELIANCE ON THIRD PARTIES TO SUPPLY NATURAL GAS RISK. We rely on third parties to supply the natural gas in our distribution segment, and limitations on our ability to obtain supplies, or failure to receive expected supplies for which we have contracted, could have an adverse impact on our financial results.

Our ability to secure natural gas for current and future sales depends upon our ability to purchase and receive delivery of supplies of natural gas from third parties. We, and in some cases, our suppliers of natural gas do not have control over the availability of natural gas supplies, competition for those supplies, disruptions in those supplies, priority allocations on transmission pipelines, or pricing of those supplies. Additionally, third parties on whom we rely may fail to deliver gas for which we have contracted. If we are unable to obtain, or are limited in our ability to obtain, natural gas from our current suppliers or new sources, we may not be able to meet our customers' gas requirements and would likely incur costs associated with actions necessary to mitigate services disruptions, both of which could significantly and negatively impact our results of operations.

SINGLE TRANSPORTATION PIPELINE RISK. We rely on a single pipeline company for the transportation of gas to our service territory, a disruption of which could adversely impact our ability to meet our customers’ gas requirements.

Our distribution system is directly connected to a single interstate pipeline, which is owned and operated by Northwest Pipeline. The pipeline’s gas flows are bi-directional, transporting gas into the Portland metropolitan market from two directions: (1) the north, which brings supplies from the British Columbia and Alberta supply basins; and (2) the east, which brings supplies from the Alberta and the U.S. Rocky Mountain supply basins. If there is a rupture or inadequate capacity in the pipeline, we may not be able to meet our customers’ gas requirements and we would likely incur costs associated with actions necessary to mitigate service disruptions, both of which could significantly and negatively impact our results of operations.

WEATHER RISK. Warmer than average weather may have a negative impact on our revenues and results of operations.

We are exposed to weather risk primarily in our utility segment. A majority of our volume is driven by gas sales to space heating residential and commercial customers during the winter heating season. Current utility rates are based on an assumption of average weather. Warmer than average weather typically results in lower gas sales. Colder weather typically results in higher gas sales. Although the effects of warmer or colder weather on utility margin in Oregon are expected to be mitigated through the operation of our weather normalization mechanism, weather variations from normal could adversely affect utility margin because we may be required to purchase more or less gas at spot rates, which may be higher or lower than the rates assumed in our PGA. Also, a portion of our Oregon residential and commercial customers (usually less than 10%) have opted out of the weather normalization mechanism, and 11% of

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our customers are located in Washington where we do not have a weather normalization mechanism. These effects could have an adverse effect on our financial condition, results of operations and cash flows.

CUSTOMER CONSERVATION RISK. Customers’ conservation efforts may have a negative impact on our revenues.

An increasing national focus on energy conservation, including improved building practices and appliance efficiencies may result in increased energy conservation by customers. This can decrease our sales of natural gas and adversely affect our results of operations because revenues are collected mostly through volumetric rates, based on the amount of gas sold. In Oregon, we have a conservation tariff which is designed to recover lost utility margin due to declines in residential and small commercial customers’ consumption. However, we do not have a conservation tariff in Washington that provides us this margin protection on sales to customers in that state.

RELIANCE ON TECHNOLOGY RISK. Our efforts to integrate, consolidate and streamline our operations have resulted in increased reliance on technology, the failure or security breach of which could adversely affect our financial condition and results of operations.

Over the last several years we have undertaken a variety of initiatives to integrate, standardize, centralize and streamline our operations. These efforts have resulted in greater reliance on technological tools such as: an enterprise resource planning system, an automated dispatch system, an automated meter reading system, a customer information system, a web-based ordering and tracking system, and other similar technological tools and initiatives. The failure of any of these or other similarly important technologies, or our inability to have these technologies supported, updated, expanded or integrated into other technologies, could adversely impact our operations. We take precautions to protect our systems, but there is no guarantee that the procedures we have implemented to protect against unauthorized access to secured data and systems are adequate to safeguard against all security breaches. Our utility could experience breaches of security pertaining to sensitive customer, employee and vendor information maintained by the utility in the normal course of business which could adversely affect the utility’s reputation, diminish customer confidence, disrupt operations, materially increase the costs we incur to protect against these risks, and subject us to possible financial liability or increased regulation or litigation, any of which could adversely affect our financial condition and results of operations.

Furthermore, we rely on information technology systems in our operations of our distribution and storage operations. There are various risks associated with these systems, including, hardware and software failure, communications failure, data distortion or destruction, unauthorized access to data, misuse of proprietary or confidential data, unauthorized control through electronic means, programming mistakes and other inadvertent errors or deliberate human acts. In particular, cyber security attacks, terrorism or other malicious acts could damage, destroy or disrupt all of our business systems. Any failure of

information technology systems could result in a loss of operating revenues, an increase in operating expenses and costs to repair or replace damaged assets. As these potential cyber security attacks become more common and sophisticated, we could be required to incur costs to strengthen our systems or obtain specific insurance coverage against potential losses.

Risks Related Primarily to Our Gas Storage Businesses

LONG-TERM LOW OR STABILIZATION OF GAS PRICE RISK. Any significant stabilization of natural gas prices or long-term low gas prices could have a negative impact on the demand for our natural gas storage services, which could adversely affect our financial results.

Storage businesses benefit from price volatility, which impacts the level of demand for services and the rates that can be charged for storage services. On a system-wide basis, natural gas is typically injected into storage between April and October when natural gas prices are generally lower and withdrawn during the winter months of November through March when natural gas prices are typically higher. Largely due to the abundant supply of natural gas made available by hydraulic fracturing techniques, natural gas prices have dropped significantly to levels that are near historic lows. If prices and volatility remain low or decline further, then the demand for storage services, and the prices that we will be able to charge for those services, may decline or be depressed for a prolonged period of time. Prices below the costs to operate the storage facility could result in a decision to shut in all or a portion of the facility. A sustained decline in these prices or a shut-in of all or a portion of the facility could have an adverse impact on our financial condition, results of operations and cash flows.

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

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

THIRD-PARTY PIPELINE RISK. Our gas storage businesses depend on third-party pipelines that connect our storage facilities to interstate pipelines, the failure or unavailability of which could adversely affect our financial condition, results of operations and cash flows.

Our gas storage facilities are reliant on the continued operation of a third-party pipeline and other facilities that provide delivery options to and from our storage facilities.

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Because we do not own all of these pipelines, their operation is not within our control. If the third-party pipeline to which we are connected were to become unavailable for current or future withdrawals or injections of natural gas due to repairs, damage to the infrastructure, lack of capacity or other reason, our ability to operate efficiently and satisfy our customers' needs could be compromised, thereby potentially could have an adverse impact on our financial condition, results of operations and cash flows.

OPERATIONS AT STORAGE FACILITY RISK. Operations at our Mist and Gill Ranch storage facilities involve numerous operational risks that may result in a failure to meet expectations or contractual obligations, additional or unexpected costs and other business risks that could adversely impact our financial condition, results of operations and cash flows.

Operations at a storage facility involve many risks. If we fail to inject or withdraw natural gas at the levels we expect or at contracted rates, or cannot deliver natural gas consistent with our expectations or contractual specifications, or otherwise operate as expected, or if operating costs are substantially higher than we expect or if we fail to control those costs, we may not be able to contract for storage at the levels and on the terms we expect, and we could incur higher than expected costs to satisfy our contractual obligations under contracts we obtain, and this could adversely impact our financial condition, results of operations and cash flows.

ITEM 1B. UNRESOLVED STAFF COMMENTS

We have no unresolved comments.

ITEM 2. PROPERTIES

Utility Properties

Our natural gas pipeline system consists of approximately 14,000 miles of distribution and transmission mains located in our service territory in Oregon and Washington. In addition, the pipeline system includes service pipelines, meters and regulators, and gas regulating and metering stations. Pipeline mains are located in municipal streets or alleys pursuant to franchise or occupation ordinances, in county roads or state highways pursuant to agreements or permits granted pursuant to statute, or on lands of others pursuant to easements obtained from the owners of such lands. We also hold permits for the crossing of numerous navigable waterways and smaller tributaries throughout our entire service territory.

We own service building 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 also lease office space in Portland for our corporate headquarters, which expires on May 31, 2020. Resource centers are maintained on owned or leased premises at convenient points in the distribution system to provide service within our utility service territory. We also own LNG storage facilities in Portland and near Newport, Oregon.

In order to reduce risks associated with gas leakage in older parts of our system, we undertook accelerated pipe

replacement programs under which we removed and replaced 100% of our cast iron mains by the end of 2000, and under which we expect to eliminate all remaining bare steel mains and services by the end of 2015.

Gas Storage Properties

We hold leases and other property interests in approximately 12,000 net acres of underground natural gas storage in Oregon and approximately 5,000 net acres of underground natural gas storage in California, and easements and other property interests related to pipelines associated with those facilities. We own rights to depleted gas reservoirs near Mist, Oregon, that are continuing to be developed and operated as underground gas storage facilities. We also hold an option to purchase future storage rights in certain other areas of the Mist gas field in Oregon, as well as in California related to the Gill Ranch storage project.

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

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

ITEM 3. LEGAL PROCEEDINGS

Other than the proceedings disclosed in Note 15, we have only nonmaterial litigation in the ordinary course of business.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

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

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:

	2014		2013	
Quarter Ended	High	Low	High	Low
March 31	$44.09	$40.05	$46.55	$43.40
June 30	47.32	43.06	45.89	41.17
September 30	47.50	41.81	45.15	39.96
December 31	52.57	42.29	44.35	40.75

The closing price for our common stock on December 31, 2014 and 2013 were $49.90 and $42.82, respectively.

As of February 20, 2015, there were 5,929 holders of record of our common stock.

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	2014	2013
February 15	$0.460	$0.455
May 15	0.460	0.455
August 15	0.460	0.455
November 15	0.465	0.460
Total per share	$1.845	$1.825

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

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, 2014:

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs(2)	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs(2)
Balance forward			2,124,528	$ 16,732,648
10/01/14-10/31/14	—	$—	—	—
11/01/14-11/30/14	4,233	46.22	—	—
12/01/14-12/31/14	211	47.32	—	—
Total	4,444	$46.28	2,124,528	$ 16,732,648

(1) During the quarter ended December 31, 2014, 4,444 shares of our common stock were purchased on the open market to meet the requirements of our share-based programs. During the quarter ended December 31, 2014, no

shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

(2) We have a common stock share repurchase program under which we purchase shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 31, 2015 to repurchase up to an aggregate of 2.8 million shares or up to an aggregate of $100 million. During the quarter ended December 31, 2014, no shares of our common stock were repurchased pursuant to this program. Since the program's inception in 2000, we have repurchased approximately 2.1 million shares of common stock at a total cost of approximately $83.3 million.

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ITEM 6. SELECTED FINANCIAL DATA

	For the year ended December 31,				
In thousands, except share data	2014	2013	2012	2011	2010
Operating revenues	$754,037	$758,518	$730,607	$828,055	$792,115
Net income	58,692	60,538	58,779	63,044	72,013
Earnings per share of common stock:					
Basic	$2.16	$2.24	$2.19	$2.36	$2.71
Diluted	2.16	2.24	2.18	2.36	2.70
Dividends paid per share of common stock	1.85	1.83	1.79	1.75	1.68
Total assets, end of period	$3,064,945	$2,970,911	$2,813,120	$2,742,718	$2,614,172
Total equity	767,321	751,872	729,627	712,158	691,625
Long-term debt	621,700	681,700	691,700	641,700	591,700

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

The following is management's assessment of Northwest Natural Gas Company's (NW Natural or the Company) financial condition, including the principal factors that affect results of operations. The discussion refers to our consolidated results for the years ended December 31, 2014, 2013, and 2012. References in this discussion to "Notes" are the Notes to Consolidated Financial Statements in Item 8 of this report.

The consolidated financial statements include NW Natural and its direct and indirect wholly-owned subsidiaries including:

- NW Natural Energy, LLC (NWN Energy),
- NW Natural Gas Storage, LLC (NWN Gas Storage),
- Gill Ranch Storage, LLC (Gill Ranch),
- NNG Financial Corporation (NNG Financial),
- Northwest Energy Corporation (Energy Corp), and
- NW Natural Gas Reserves, LLC (NWN Gas Reserves).

We operate in two primary reportable business segments: local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as other. We refer to our local gas distribution business as the utility, and our gas storage segment and other as non-utility. Our utility segment includes our NW Natural local gas distribution business, NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp, and the utility portion of our Mist underground storage facility in Oregon (Mist). Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and asset management services. Other includes NWN Energy's equity investment in Trail West Holding, LLC (TWH), which is pursuing the development of a proposed natural gas pipeline through its wholly-owned subsidiary, Trail West Pipeline, LLC (TWP), and NNG Financial's equity investment in Kelso-Beaver Pipeline (KB Pipeline). For a further discussion of our business segments and other, see Note 4.

In addition to presenting results of operations and earnings amounts in total, certain financial measures are expressed in cents per share, which are non-GAAP financial measures. These amounts reflect factors that directly impact earnings, including income taxes. All references in this section to earnings per share (EPS) are on the basis of diluted shares. We use such non-GAAP measures in analyzing our financial performance because we believe they provide useful information to our investors and creditors in evaluating our financial condition and results of operations.

EXECUTIVE SUMMARY

Our 2014 performance reflects the execution of our long-term business strategy and advancement of our initiatives. Highlights for the year include:

- increased the annual customer growth rate in core utility for the third year in a row from 0.8% to 1.4% at December 31, 2014;
- invested $120.1 million in our system and facilities including $30.4 million on SIP, allowing us to approach the completion of our bare steel replacement, and announced a proposed gas storage expansion at Mist;
- received proceeds from environmental insurance settlements, bringing total insurance recoveries to $103 million in 2014 and over $150 million cumulatively;
- launched a new online tool for customers and trade allies that enables online ordering of services, tracking progress of orders, and managing multiple projects;

- ranked first in residential customer satisfaction for large gas utilities in the West in the 2014 J.D. Power and Associates Study, making 2014 the 13th consecutive year of top three rankings; and
- increased the dividend, marking the 59th consecutive year of increases.

We manage our business and strategic initiatives with a long-term view on providing natural gas service safely and reliably to customers, working with regulators on key policy initiatives, and remaining focused on growing our business. See "2015 Outlook" below for more information.

Key financial highlights include:

In millions, except per share data	2014	2013	2012
Consolidated net income	$58.7	$60.5	$58.8
Consolidated EPS	2.16	2.24	2.18
Utility margin	366.1	353.9	344.5

Net income and EPS for 2014 reflected the following:

- utility net income increased $3.7 million on utility margin growth of $12.2 million primarily due to customer growth and rate-base returns on gas reserves and other investments; and
- gas storage net income declined $5.9 million primarily due to lower operating revenues from re-contracting certain expiring capacity at lower prices for the 2014-15 gas storage year.

See "Consolidated Earnings and Dividends" below for additional detail.

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2015 OUTLOOK

Our near-term outlook and long-term strategic goals for the business are aligned with delivering gas safely and reliably to our customers, investing for profitable growth in our core gas distribution and gas storage businesses, and creating new ideas to drive growth opportunities. Our 2015 strategy leverages our resources and our history of innovative solutions to continue meeting the needs of customers, regulators, and shareholders. We consider the following goals critical in achieving these long-term goals:

Deliver Gas	Grow Our Businesses
Ensure Safety and Reliability	Grow Utility Customers
Advance Regulatory Policies and Initiatives	Pursue Strategic Utility Investments
Promote Sustainable Energy Policies	Develop Non-utility Growth Initiatives

SAFETY AND RELIABILITY. Delivering natural gas safely and reliably to customers and providing employees with a safe work environment are our top priorities. During 2015, we will continue to ensure our pipeline system and facilities are well maintained, new facility improvements are planned and well executed, and business continuity requirements are met. In addition, the removal of all bare steel pipe from our system is set to be achieved by the end of 2015.

In 2014 we filed our IRP with the OPUC and WUTC, identifying investments needed to ensure our system will continue meeting customer demands. In February 2015, the OPUC acknowledged the IRP. We will continue working on key infrastructure investments for high-growth areas of our service territory and plan for necessary maintenance of our utility and storage facilities.

REGULATION. Constructive regulation supports customers receiving quality service at a reasonable cost and the company receiving timely cost recovery and earning a reasonable return on shareholder investments. During 2015, we will implement our new Site Remediation and Recovery Mechanism (SRRM). This mechanism reflects the deep, shared commitment of the Company and its customers to the environment. In addition, we continue to work with regulators on environmental sustainability projects such as new carbon solution incentive rate mechanisms.

ENERGY POLICIES. The Pacific Northwest is committed to energy conservation, environmental sustainability, and reducing carbon emissions. Natural gas is an important clean energy resource for our region and the country. Natural gas can play an important role in supporting the integration of intermittent renewable resources into the electric power system, and therefore, complements wind and solar renewable energy options. In 2015, we will continue to play an active role in shaping energy policies and programs, which reflect the interests of our customers. We will continue to work with state legislators to build a strong energy plan for the region, and we will remain committed to working with environmental agencies to make significant progress towards remediation of our legacy environmental sites.

UTILITY CUSTOMERS. Natural gas is a preferred energy resource in our service territory as it is a low-cost, reliable, and clean energy choice. We intend to capitalize on this preference and on improvements in the residential housing and commercial markets to grow our customer base.

KEY UTILITY INVESTMENTS. We believe investing in new infrastructure, operating efficiencies, and marketing opportunities positions our core business for growth now and well into the future. During 2015, we will continue working on a number of carbon solution programs with the OPUC, such as residential oil conversions, commercial combined heat and power, and other carbon emission reduction programs.

Our recent IRP filing indicates an increase in the demand for natural gas in our region and the need for additional infrastructure investments. Our utility and gas storage operations in Oregon and SW Washington currently depend on a single bi-directional interstate transmission pipeline to transport gas supplies to customers. We will continue to work with regulators, customers, and utilities in the Pacific Northwest to advance a new, integrated, regional cross-Cascades pipeline to create supply diversity and reliability for our system. The need for gas supply flexibility increases as additional large electric generation and industrial projects are sited in the region.

A growth investment for our storage business is the planned expansion at Mist to support a gas-fired plant built by Portland General Electric (PGE) at their nearby Port Westward facility. In early 2015, we were authorized by PGE to begin permitting and land acquisition work for this project. Before construction can begin, the project is subject to several conditions, including, but not limited to, PGE's final approval of estimated costs and receipt of a notice to proceed.

NON-UTILITY INITIATIVES. Energy policies in the Pacific Northwest and California are likely to increase the value of the Company's gas storage in the long-term. In the short-term, we remain focused on maximizing the value of our storage assets by managing costs, optimizing revenue opportunities, and seeking new potential markets and customers, while recognizing the unique challenges low, stable natural gas prices bring to the storage market.

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Issues and Challenges

ECONOMY. The local, national, and global economies showed signs of improvement during 2014. We saw increased utility customer growth and business demand for natural gas. Our utility’s customer growth rate was 1.4% in 2014, compared to 1.3% in 2013 and 0.9% in 2012. NW Natural ended 2014 with 704,644 customers. The local Oregon and southwest Washington economies are showing signs of recovery as unemployment rates in the Portland and Vancouver area dropped from approximately 7% in 2013 to approximately 6% at the end of 2014. We believe our utility is well positioned for continued customer additions and increasing industrial demand because of low, stable natural gas prices, our relatively low market penetration, and our ongoing focus of converting homes and businesses to natural gas. Additional growth may also come with increased industrial load from new projects in the region and proposed legislation that favors lower carbon emissions and lower cost energy alternatives, such as natural gas. Our gas storage business is also impacted by the employment trends throughout the West Coast, as California, which was among the hardest hit areas during the recession, is reporting lower unemployment levels in 2014.

GAS PRICES AND SUPPLIES. Our gas acquisition strategy is to secure sufficient supplies of natural gas to meet the needs of our utility customers and to hedge gas prices so we can effectively manage costs, reduce price volatility, and maintain a competitive price advantage. With developments in drilling technologies and the abundance of shale development around the U.S. and in Canada, the current outlook for North American natural gas supply is strong and is projected to remain this way into the future. This projection is dependent upon a combination of supply outlook and demand factors as well as a regulatory environment that continues to support hydraulic fracturing and other drilling technologies.

Our utility's annual PGA mechanisms in Oregon and Washington, combined with our gas price hedging strategies, enable us to reduce earnings exposure for the Company and secure lower gas costs for our customers. Each year, we typically hedge gas prices on approximately 75% of our utility's annual sales requirement based on normal weather, including both physical and financial hedges. We entered the 2014-15 gas year (November 1, 2014 - October 31, 2015) hedged at 75% of our forecasted sales volumes, including 41% in financial swap and option contracts and 34% in physical gas supplies. For further discussion see "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment" below.

In addition to the amount hedged for the current gas contract year, we are also hedged in future years at approximately 18% for the 2015-16 gas year as of December 31, 2014 and between 1% and 9% for annual requirements over the following five gas years. Our hedge levels are subject to change based on actual load volumes, which depend to a certain extent on weather, economic conditions, and estimated gas reserve production. Also, our storage inventory levels may increase or decrease based on storage expansion, changes in storage contracts with third parties, and/or storage recall by the utility.

While low and stable gas prices provide opportunities to lower costs for our utility customers, they also present challenges for our gas storage businesses by lowering the price of, and reducing the demand for, storage services. Earlier this year we re-contracted certain expiring storage customer capacity at our Gill Ranch facility for the 2014-15 gas storage year at historically low prices due to the flat natural gas price curve and generally weak market conditions, which negatively impacted our financial results. However, increases in demand for natural gas or decreases in supplies can put upward pressure on gas prices and gas price volatility, which could improve the market value for gas storage. Similarly, decreases in demand and increases in supplies can cause downward pressure on gas prices and gas price volatility. We are seeing slightly higher contract prices for the upcoming storage year, but overall prices are lower than our long-term contracts that expired during the 2013-14 gas storage year. As such, we continue to expect shorter contract lengths and prices reflecting current market trends and remain focused on lowering operating costs, finding opportunities in the market to increase revenues through enhanced services for storage customers, and capitalizing on market opportunities that fit our business-risk profile.

ENVIRONMENTAL COSTS. We accrue all material environmental loss contingencies related to environmental sites for which we are responsible. Due to numerous uncertainties surrounding the nature of environmental investigations and the approval of proposed remediation solutions by regulatory agencies, actual costs could vary significantly from our loss estimates. As a regulated utility, we have been allowed to defer certain costs pursuant to regulatory orders. In our 2012 general rate case, the OPUC approved our recovery of environmental costs from investigation and site remediation subject to certain conditions including a site remediation and recovery mechanism. In February 2015, the OPUC issued an order regarding the mechanism as noted in "Results of Operations—Regulatory Matters—Rate Mechanisms" below and Note 16.

We have received approximately $150 million cumulatively from environmental insurance policy litigation settlements to apply toward environmental costs, and will only seek recovery from customers for amounts in excess of insurance proceeds. Ultimate recovery of environmental costs from regulated utility rates depends on our ability to effectively manage these costs and demonstrate costs were prudently incurred, and the application of an annual earnings test in Oregon. Environmental cost recovery and carrying charges on amounts charged to Washington customers will be determined in a future proceeding. See "Results of Operations—Regulatory Matters—Rate Mechanisms" below and Note 16.

CLIMATE CHANGE. We recognize our business will likely be impacted by future carbon constraints. To address these possible constraints, we are seeking clean energy growth opportunities that position us for long-term success in a lower carbon energy economy and to advance our customers' interests in energy conservation, efficiency and environmental stewardship. A variety of federal, state, local, and international climate change initiatives, including new regulations, are underway, but we cannot determine the

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impact of these initiatives at this time. For example, an array of Environmental Protection Agency (EPA) rules impacting coal plants has driven some coal plants to shut down early although the EPA is not mandating coal plant closures. Coal plant shut downs could increase the demand for natural gas as a lower carbon emission fuel and create opportunities for us. Similarly, because natural gas has a relatively low carbon content, it is also possible future carbon constraints could create additional demand for natural gas for base load electric generation, direct use in homes and businesses, backing up intermittent renewable resources, and as a transportation fuel to displace gasoline and diesel fuels.

As required under EPA greenhouse gas regulations, we annually report our system throughput and unintended greenhouse gas releases. While our carbon dioxide equivalent emission levels are relatively small, the adoption and implementation of any regulations imposing reporting obligations, or limiting emissions of greenhouse gases associated with our operations, could result in an increase in the prices we charge our customers or a decline in the demand for natural gas.

CONSOLIDATED EARNINGS AND DIVIDENDS

Consolidated Earnings

Consolidated highlights include:

In millions, except EPS data	2014		2013		2012	
Net income	$58.7		$60.5		$58.8	
EPS	2.16		2.24		2.18	
ROE	7.7	%	8.2	%	8.2	%

2014 COMPARED TO 2013. Overall, consolidated net income decreased $1.8 million. Our net income is most significantly impacted by our utility business which had favorable results during the year, but increases at the utility were more than offset by declines from our gas storage segment. The primary factors were:

- a $12.2 million increase in utility margin primarily due to customer growth and the rate-base return on our gas reserves and other investments;
- a $8.9 million decrease in gas storage operating revenues as storage was negatively impacted by re-contracting certain expiring firm storage capacity at lower prices;
- a $3.3 million increase in depreciation and amortization expenses due to additional utility capital expenditures; and
- a $2.7 million decrease in other income and expense, net due to lower interest income on net deferred regulatory balances.

2013 COMPARED TO 2012. The most significant factors contributing to the $1.8 million increase in consolidated net income were:

- a $9.4 million increase in utility margin primarily due to customer growth and the rate-base return on our gas reserves and other investments; and
- a $2.7 million after-tax charge taken in 2012 from an Oregon general rate case disallowance.

Partially offsetting the above factors were:

- a $7.1 million increase in operations and maintenance expense primarily due to increased utility payroll and system maintenance and safety program costs; and
- a $2.9 million increase in depreciation and amortization expenses primarily due to additional utility expenditures.

Dividends

Dividend highlights include:

Per common share	2014	2013	2012
Dividends paid	$1.85	$1.83	$1.79

The Board of Directors declared a quarterly dividend on our common stock of $0.465 cents per share, payable on February 13, 2015, to shareholders of record on January 30, 2015, reflecting an indicated annual dividend rate of $1.86 per share.

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RESULTS OF OPERATIONS

Regulatory Matters

Regulation and Rates

UTILITY. Our utility business is subject to regulation by the OPUC, WUTC, and FERC with respect to, among other matters, rates and terms of service. The OPUC and WUTC also regulate the system of accounts and issuance of securities by our utility. In 2014, approximately 89% of our utility gas volumes and revenues were derived from Oregon customers, with the remaining 11% from Washington customers. Earnings and cash flows from utility operations are largely determined by rates set in general rate cases and other proceedings in Oregon and Washington, but are also affected by the local economies in Oregon and Washington, the pace of customer growth in the residential, commercial, and industrial markets, and our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery of our utility-related costs, including operating expenses and investment costs in utility plant and other regulatory assets. See "Most Recent General Rate Cases" below.

GAS STORAGE. Our gas storage business is subject to regulation by the OPUC, WUTC, CPUC, and FERC with respect to, among other matters, rates and terms of service. The OPUC and CPUC also regulate the issuance of securities and system of accounts. The OPUC and CPUC regulate intrastate storage services, and the FERC regulates interstate storage services. The OPUC and FERC use a maximum cost of service model which allows for gas storage prices to be set at or below the cost of service as approved by each agency in the last regulatory filing. The CPUC regulates Gill Ranch under a market-based rate model which allows for the price of storage services to be set by the marketplace. In 2014, approximately 69% of our storage revenues were derived from FERC, Oregon, and Washington regulated operations and approximately 31% from California operations.

Most Recent General Rate Cases

OREGON. Effective November 1, 2012, the OPUC authorized rates to customers based on an ROE of 9.5%, an overall rate of return of 7.78%, and a capital structure of 50% common equity and 50% long-term debt.

WASHINGTON. Effective January 1, 2009, the WUTC authorized rates to customers based on an ROE of 10.1% and an overall rate of return of 8.4% with a capital structure of 51% common equity, 5% short-term debt, and 44% long-term debt.

FERC. We are required under our Mist interstate storage certificate authority and rate approval orders to file every five years either a petition for rate approval or a cost and revenue study to change or justify maintaining the existing rates for our interstate storage services. In December 2013 we filed a rate petition, which was approved in 2014 and allows for the maximum cost-based rates for our interstate gas storage services. These rates were effective January 1, 2014, with the rate changes having no significant impact on our revenues.

Open Regulatory Proceedings

The following provides a list of our significant open regulatory items:

- Interstate Storage Sharing - A docket has been
opened to review the current revenue sharing arrangement that allocates a portion of the net revenues generated from non-utility Mist storage services and third-party asset management services to utility customers. We anticipate resolution of this docket in 2015.

- Prepaid Pension Asset - A schedule was established to resolve this docket in 2015. See "Rate Mechanisms—Pension Cost Deferral and Prepaid Pension Assets" below.
- Gas Reserves - We filed with the OPUC in February 2015 seeking cost recovery on additional investments in gas reserves. See "Rate Mechanisms—Gas Reserves" below.
- Integrated Resource Plan (IRP) - We filed our 2014 Oregon and Washington IRPs on August 29, 2014 and received acknowledgment from the OPUC on February 24, 2015. We expect notice from the WUTC during 2015. The IRPs included analysis of different market scenarios and corresponding resource acquisition strategies. This analysis is needed to develop supply and demand resource requirements, consider uncertainties in the planning process, and to establish a plan for providing reliable and low cost natural gas service.
- System Integrity Program (SIP) - We filed a request to extend the SIP program in the fourth quarter of 2014. See "Rate Mechanisms—System Integrity Program (SIP)" below.

Completed Regulatory Activities

The following provides a list of our completed regulatory activities in 2014:

- Flexible Gas Storage - We received approval from the OPUC in 2014 for two new rate schedules. One of these schedules is intended to allow us to provide no-notice gas storage service from Mist and specifically supports services associated with the proposed Mist gas storage facility expansion. The expansion would be supported by a contract with PGE to serve their gas-fired electric power generation facilities at Port Westward, which is located approximately 15 miles from Mist. In early 2015, we received authorization from PGE to begin permitting and land acquisition work. This project is subject to PGE's final approval of estimated projected costs and a notice to proceed, as well as the receipt of permits and certain land rights, among other conditions.
- Senate Bill (SB) 844 - Final rules for gas utilities in Oregon governing the incentive rate-making mechanisms aimed at reducing greenhouse gas emissions were issued in 2014. We anticipate submitting programs developed under these rules to the OPUC in 2015. These programs include oil conversions, commercial combined heat and power, and other carbon emission reduction programs.
- GASCO Water Treatment Station - The OPUC approved placing $19.0 million of capital costs

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associated with a water treatment station at our Gasco environmental site into rates effective November 1, 2013. During 2014, the OPUC deemed Gasco construction costs prudent and approved the application of $2.5 million of insurance proceeds plus interest to reduce the capital costs included in rates effective November 1, 2014.

- CNG Service Approved - In 2014, we received approval from the OPUC to offer business customers a new service to install, own, and maintain gas compression equipment that enables them to fuel their vehicle fleets with CNG. NW Natural filed the tariff in June 2013 after receiving requests from businesses interested in switching or increasing the number of their fleet vehicles fueled by CNG. Costs associated with providing this service will be directly paid by business customers using the service. The OPUC will review the tariff after two years to assess the market for CNG at that time.

Rate Mechanisms

PURCHASED GAS ADJUSTMENT. Rate changes are established for the utility each year under PGA mechanisms in Oregon and Washington to reflect changes in the expected cost of natural gas commodity purchases. This includes gas prices under spot purchases as well as contract supplies, gas prices hedged with financial derivatives, gas prices from the withdrawal of storage inventories, the production of gas reserves, interstate pipeline demand costs, a permanent rate adjustment for our SIP program, temporary rate adjustments, which amortize balances of deferred regulatory accounts, and the removal of temporary rate adjustments effective for the previous year.

Under the current PGA mechanism in Oregon, there is an incentive sharing provision whereby we are required to select each year either an 80% deferral or a 90% deferral of higher or lower actual gas costs compared to estimated PGA prices, such that the impact on current earnings from the incentive sharing is either 20% or 10% of the difference between actual and estimated gas costs, respectively. Under the Washington PGA mechanism, we defer 100% of the higher or lower actual gas costs, and those gas cost differences are normally passed on to customers through the annual PGA rate adjustment.

We filed our PGA in September 2014 and received OPUC and WUTC approval in October 2014. PGA rate changes were effective November 1, 2014, with the rate changes increasing the average monthly bills of residential customers by 1.7% and 6.0% in Oregon and Washington, respectively. The increase in Oregon reflected customers' portion of adjustments for changes in natural gas commodity costs, offset by credits related to the decoupling mechanism and other annual adjustments previously agreed to with the OPUC. Washington rates reflected the full effect of changes in natural gas commodity costs and some additional annual adjustments based on ongoing agreements with the WUTC.

Commodity cost increases were primarily related to the colder weather experienced by many parts of the United States for an extended period in late 2013 and early 2014. The extreme cold weather nationally resulted in a significant withdrawal of gas from storage and higher gas prices compared to the 2012-13 winter. In addition, our service territory experienced a cold weather event in February 2014, increasing gas volumes purchased for that period. These past and current price and volume increases resulted in the rate changes for the 2014-15 PGA period.

EARNINGS TEST REVIEW. We are subject to an annual earnings review in Oregon to determine if the utility is earning above its authorized ROE threshold. If utility earnings exceed a specific ROE level, then 33% of the amount above that level is required to be deferred for refund to customers. Under this provision, if we select the 80% deferral gas cost option, then we retain all of our earnings up to 150 basis points above the currently authorized ROE. If we select the 90% deferral option, then we retain all of our earnings up to 100 basis points above the currently authorized ROE. We selected the 90% deferral option for the 2012-13, 2013-14 and 2014-15 PGA years. The ROE threshold is subject to adjustment annually based on movements in long-term interest rates. For calendar years 2012, 2013, and 2014, the ROE threshold was 10.92%, 10.58%, and 10.66%, respectively. There were no refunds required for 2012 and 2013. We do not expect a refund for 2014 based on our results and anticipate filing the 2014 test in May 2015.

GAS RESERVES. In 2011 the OPUC approved the Encana gas reserve transaction to provide long-term gas price protection for our utility customers and determined the Company's costs under the agreement will be recovered, plus a rate base return on our investment, on an ongoing basis through our annual PGA mechanism, including the regulatory deferral and incentive sharing process for the commodity cost of gas. Gas produced from our interests is sold by Encana at then prevailing market prices with revenues from such sales, net of associated operating and production costs, credited to our cost of gas. Annually, a forecast is established for the amounts related to revenues, costs, and production volumes expected, and any variances between forecasted and actual results are subject to our PGA incentive sharing in Oregon.

On March 28, 2014, we amended the original gas reserve agreement in order to facilitate Encana's proposed sale of its interest in the Jonah field to Jonah Energy, LLC. Under the amendment, we ended the drilling program with Encana, but increased our assigned ownership interests in certain sections of the Jonah field and retained the right to invest in additional wells with the new owner.

In 2014 we elected to participate in some of the additional wells drilled in the Jonah field under our amended gas reserves agreement with Jonah Energy, LLC and may have the opportunity to participate in more wells in the future. We filed an application requesting regulatory deferral in Oregon for these additional investments. We filed in February 2015 seeking cost recovery for the additional wells drilled in 2014 and expect a decision on the prudence of these wells in 2015.

DECOUPLING. Decoupling is intended to break the link between utility earnings and the quantity of gas consumed by customers, removing any financial incentive by the utility to discourage customers’ efforts to conserve energy.

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The Oregon decoupling mechanism was reauthorized in the 2012 Oregon general rate case with the baseline determined in our 2012 general rate case being used in base rates. This mechanism employs a use-per-customer decoupling calculation, which adjusts margin revenues to account for the difference between actual and expected customer volumes. The margin adjustment resulting from differences between actual and expected volumes under the decoupling component is recorded to a deferral account, which is included in the annual PGA filing. Baseline consumption reflects forecasted customer consumption data used in the Oregon general rate case. In Washington, customer use is not covered by such a tariff. See "Business Segments—Local Gas Distribution Utility Operations" below.

WEATHER NORMALIZATION TARIFF. In Oregon, we have an approved weather normalization mechanism, which is applied to residential and commercial customer bills. This mechanism is designed to help stabilize the collection of fixed costs by adjusting residential and commercial customer billings based on temperature variances from average weather, with rate decreases when the weather is colder than average and rate increases when the weather is warmer than average. The mechanism is applied to bills from December through May of each heating season. The mechanism adjusts the margin component of customers’ rates to reflect average weather, which uses the 25-year average temperature for each day of the billing period. Daily average temperatures and 25-year average temperatures are based on a set point temperature of 59 degrees Fahrenheit for residential customers and 58 degrees Fahrenheit for commercial customers. This weather normalization mechanism was reauthorized in the 2012 Oregon general rate case without an expiration date. Residential and commercial customers in Oregon are allowed to opt out of the weather normalization mechanism, and as of December 31, 2014, 7% of total customers had opted out. We do not have a weather normalization mechanism approved for residential and commercial Washington customers, which account for about 11% of total customers. See "Business Segments—Local Gas Distribution Utility Operations" below.

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

SYSTEM INTEGRITY PROGRAM (SIP). Since 2002, various laws requiring minimum standards for integrity management programs and SIPs for natural gas transmission and distribution pipelines have been enacted. In January 2012 the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law and requires increased civil penalties for pipeline safety violations, improvements in prevention programs for pipelines, and additional review and analysis of various aspects of gas transmission lines. We work diligently with industry associations and federal and state regulators to ensure our compliance with the provisions of new laws.

The OPUC approved specific accounting treatment and cost recovery for our transmission pipeline integrity management program, our SIP, and for related pipeline safety rules adopted by the U.S. Department of Transportation’s PHMSA. In addition, the OPUC provided a two-year extension to November 2014 of our capital expenditure tracking mechanism to recover capital costs related to SIP. We recorded the costs related to the integrity management program as either capital expenditures or regulatory assets, accumulated the costs over each 12-month period, and recovered the revenue requirement associated with these costs, subject to audit, through rate changes effective with the Oregon annual PGA. Our SIP costs were tracked into rates annually, with rate base recovery after the first $4 million of capital costs. An annual cap for expenditures was set at $12 million, but extraordinary costs above the cap could have been approved with written consent of the OPUC staff and other interested parties and approval of the OPUC. During 2013, the Commission approved a temporary increase to the annual cap, authorizing an additional $13.7 million of expenditures above the cap over the following two years to be tracked into rates. With the increased cap, we plan to complete our bare steel replacement by the end of 2015, and as a result of this stipulation we are precluded from tracking additional bare steel replacement costs into rates after 2015. We do not have any special accounting or rate treatment for SIP costs incurred in the state of Washington.

We filed a request to extend the SIP program in the fourth quarter of 2014, with slightly modified program parameters. Specifically, we are seeking to track $8 million of SIP capital costs into rates annually, after having the first $1 million of SIP capital spend subject to regulatory lag. We expect to resolve this request during 2015.

ENVIRONMENTAL COST DEFERRAL AND SRRM. The OPUC has authorized the deferral of environmental costs associated with certain named sites and the accrual of carrying costs on amounts deferred, subject to an annual demonstration that we have maximized our insurance recovery or made substantial progress in securing insurance recovery for unrecovered environmental expenses. Through a series of extensions, the OPUC has authorized us to defer environmental costs and accrued carrying costs through January 2015, and the Company has filed a docket requesting authorization to defer costs through January 2016.

On February 20, 2015, the OPUC issued an order regarding the Site Remediation and Recovery Mechanism (SRRM) for recovering prudently incurred environmental site remediation costs through customer billings, subject to an earnings test. The OPUC order addressed a number of key issues including: (1) prudence of all but $33 thousand of costs incurred through March 31, 2014; (2) insurance settlement proceeds of approximately $150 million were deemed prudent with one-third of the proceeds applied to costs prior to December 31, 2012 and two-thirds to offset future environmental expenses; (3) in the order, the OPUC disallowed recovery of expenses totaling approximately $15 million for costs related to 2003 to 2012.

With respect to remediation expenses deferred after 2012, an aggregate of two-thirds of the environmental insurance receipts, plus interest will be applied ratably over 20 years and the remainder will be collected through the SRRM, and subject to an earnings test as follows: (1) The Company will recover the first $5 million of annual expense through a tariff rider from customers; (2) the Company will apply $5 million of insurance (plus interest accrued on insurance proceeds) to environmental expenses each year; and (3) any expenditures above the $10 million (plus interest) described above would be fully recoverable through the SRRM, to the extent the Company earns at or below its authorized Return on Equity (ROE). See Note 16 for additional detail regarding the earnings test and additional conditions related to these amounts.

The Company continues to evaluate the effects of the order and is required to file a compliance report with the OPUC within 30 days of the order demonstrating how it will be implemented. See Note 15 and Note 16 for additional detail.

The WUTC also authorized the deferral of environmental costs, if any, that are appropriately allocated to Washington customers. This order was effective January 26, 2011 with cost recovery and a carrying charge to be determined in a future proceeding.

PENSION COST DEFERRAL AND PREPAID PENSION ASSETS. Effective January 1, 2011, the OPUC approved our request to defer annual pension expenses above the amount set in rates, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of higher and lower pension expenses in future years. Our recovery of these deferred balances includes accrued interest on the account balance at the utility’s authorized rate of return, which is currently 7.78%. Future years’ deferrals will depend on changes in plan assets and projected benefit liabilities based on a number of key assumptions, and our pension contributions. Pension expense deferrals were $4.6 million and $9.1 million in 2014 and 2013, respectively. See "Application of Critical Accounting Policies and Estimates" below. As noted above, the Company continues to seek rate treatment for amounts invested in prepaid pension assets.

A prepaid pension asset docket was opened in 2013 to evaluate pension cost recovery for all utilities in Oregon. The utilities have requested recovery of the financing costs incurred as a result of timing differences between cash contributions made to their pension plans and the recognition of expense. A schedule was established to resolve this docket in 2015. As noted above, the Company currently recovers a portion of pension expense in rates and has requested continued recovery of these expenses in the docket.

CUSTOMER CREDITS FOR GAS STORAGE SHARING. On an annual basis, we credit amounts to Oregon and Washington customers as part of our regulatory incentive sharing mechanism related to net revenues from gas storage and asset management of pipeline capacity and gas storage at Mist. Generally amounts are credited to Oregon customers in June, while credits are given to customers in Washington through reductions in rates in the annual PGA filing in November.

following table presents the credits to customers:

In millions	2014	2013	2012
Oregon utility customer credit	$11.4	$8.8	$9.2
Washington utility customer credit	0.8	0.5	0.8

Business Segments - Local Gas Distribution Utility Operations

Our utility margin results are largely affected by customer growth and, to a certain extent, by changes in volume due to weather and customers’ gas usage patterns. In Oregon, we have a conservation tariff and a weather normalization tariff; both mechanisms are designed to reduce the volatility of our utility’s earnings and customer charges. See

"Regulatory Matters—Rate Mechanisms" above.

Utility segment highlights include:

Dollars and therms in millions, except EPS data	2014	2013	2012
Utility net income	$58.6	$54.9	$54.0
EPS - utility segment	2.15	2.03	2.01
Gas sold and delivered (in therms)	1,093	1,146	1,112
Utility margin[1]	$366.1	$353.9	$344.5

[1] See Utility Margin Table below for a reconciliation and additional detail.

2014 COMPARED TO 2013. The primary factors contributing to the $3.7 million or $0.12 per share increase in net income were as follows:

- a $12.2 million net increase in utility margin primarily due to:
  - a $16.6 million increase from customer growth in residential and commercial customers, industrial margins, and added rate-base returns on certain investments, including gas reserves; partially offset by
  - $2.1 million increase in loss from gas cost incentive sharing mainly resulting from higher gas prices and volumes than those estimated in the PGA; and
  - the remaining decrease was primarily due to warmer weather as measured by heating degree days, in Washington, which does not have a weather normalization mechanism in place, and the effect of warmer weather on margin for Oregon customers that opt out of weather normalization.
- a $3.2 million increase in depreciation expense due to additional capital expenditures;
- a $1.5 million decrease in operations and maintenance expense; and
- a $2.1 million decrease in other income and expense, net primarily due to lower interest income on regulatory deferred account balances.

Total utility volumes sold and delivered in 2014 decreased 5% over 2013 primarily due to the impact of warmer weather on residential and commercial use.

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2013 COMPARED TO 2012. The primary factors contributing to the $0.9 million or $0.02 per share increase in net income were as follows:

- a $9.4 million net increase in utility margin primarily due to:

a $10.8 million increase related to customer growth and the rate-base return on our gas reserves and other investments, such as our pipeline integrity tracker; and

a $3.9 million increase related to the timing impacts of changes in fixed monthly charges and decoupling baselines in the 2012 Oregon general rate case. As a result of changes to the decoupling baseline for average use per customer included in the 2012 rate case, the decoupling mechanism's results in 2013 were not comparable to 2012, although the overall impact on revenues was generally the same on an annualized basis.

These increases in margin were partially offset by:

a $3.9 million decrease in gains from gas cost incentive sharing due to actual gas prices that were roughly equivalent to estimated PGA prices for 2013 as compared to actual gas prices that were lower than estimated PGA prices for 2012; and

a $1.4 million decrease primarily related to the lower Oregon Authorized ROE of 9.5% from the 2012 general rate case.

- a $1.5 million increase in other income and expense, net primarily due to interest on higher average regulatory account balances; and
- a $2.7 million tax charge taken in 2012 from an Oregon general rate case disallowance. See "Application of Critical Accounting Policies and Estimates—Regulatory Accounting" below.

These factors were partially offset by:

- a $7.4 million increase in operations and maintenance expense primarily due to increased utility payroll and system maintenance and safety program costs;
- a $2.9 million increase in depreciation and amortization expense primarily due to a higher level of investment in utility property, plant, and equipment; and
- a $2.4 million increase in interest expense primarily due to increases in long-term debt outstanding.

Total utility volumes sold and delivered in 2013 increased 3% over 2012 primarily due to the impact of colder weather on residential and commercial use.

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UTILITY MARGIN TABLE. The following table summarizes the composition of utility gas volumes, revenues, and cost of sales:

In thousands, except degree day and customer data	2014	2013	2012	Favorable/(Unfavorable) 2014 vs. 2013	Favorable/(Unfavorable) 2013 vs. 2012
Utility volumes (therms):					
Residential and commercial sales	620,903	671,906	637,885	(51,003)	34,021
Industrial sales and transportation	472,087	474,525	473,884	(2,438)	641
Total utility volumes sold and delivered	1,092,990	1,146,431	1,111,769	(53,441)	34,662
Utility operating revenues:					
Residential and commercial sales	$672,440	$673,250	$642,337	$(810)	$30,913
Industrial sales and transportation	73,992	68,880	70,020	5,112	(1,140)
Other revenues	3,983	4,054	5,935	(71)	(1,881)
Less: Revenue taxes	18,837	19,002	18,430	(165)	572
Total utility operating revenues	731,578	727,182	699,862	4,396	27,320
Less: Cost of gas	365,490	373,298	355,335	(7,808)	17,963
Utility margin	$366,088	$353,884	$344,527	$12,204	$9,357
Utility margin:(1)					
Residential and commercial sales	$334,247	$321,608	$306,382	$12,639	$15,226
Industrial sales and transportation	29,982	28,335	28,586	1,647	(251)
Miscellaneous revenues	4,329	4,308	4,452	21	(144)
Gain (loss) from gas cost incentive sharing	(2,135)	(41)	3,811	(2,094)	(3,852)
Other margin adjustments	(335)	(326)	1,296	(9)	(1,622)
Utility margin	$366,088	$353,884	$344,527	$12,204	$9,357
Degree Days					
Average(2)	4,240	4,240	4,279	—	(39)
Actual	3,792	4,379	4,152	(13)%	5%
Percent colder (warmer) than average weather(2)	(11)%	3%	(3)%		
Customers - end of period:					
Residential customers	637,411	628,634	621,399	8,777	7,235
Commercial customers	66,304	65,321	63,619	983	1,702
Industrial customers	929	918	923	11	(5)
Total number of customers	704,644	694,873	685,941	9,771	8,932

(1) Amounts reported as margin for each category of customers are operating revenues, which are net of revenue taxes, less cost of gas.

(2) Average weather represents the 25-year average degree days, as determined in our Oregon general rate case. For 2014 and 2013, average weather represents the 25-year average degree days as set in our 2012 Oregon general rate case. For 2012, average weather represents degree days based on the 25-year average set in our 2003 Oregon general rate for the months of January through October, plus the 25-year average set in the 2012 Oregon general rate case for the months of November and December.

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Residential and Commercial Sales

The primary factors that impact results of operations in the residential and commercial markets are customer growth, seasonal weather patterns, energy prices, competition from other energy sources, and economic conditions in our service areas. The impact of weather on margin is significantly reduced through our weather normalization mechanism in Oregon; approximately 83% of our total customers are covered under this mechanism. The remaining customers either opt out of the mechanism or are located in Washington, which does not have a similar mechanism in place. For more information on our weather mechanism, see "Regulatory Matters—Rate Mechanisms—Weather Normalization Tariff" above.

Residential and commercial sales highlights include:

In millions	2014	2013	2012
Volumes (therms):			
Residential sales	381.5	418.6	395.5
Commercial sales	239.4	253.3	242.4
Total volumes	620.9	671.9	637.9
Operating revenues:			
Residential sales	$441.5	$447.4	$428.5
Commercial sales	230.9	225.9	213.8
Total operating revenues	$672.4	$673.3	$642.3
Utility margin:			
Residential:			
Sales	$223.6	$234.1	$211.6
Weather normalization	5.1	(9.0)	(0.1)
Decoupling	4.0	2.6	8.6
Total residential utility margin	232.7	227.7	220.1
Commercial:			
Sales	91.6	92.1	84.0
Weather normalization	2.2	(4.0)	0.2
Decoupling	7.7	5.8	2.1
Total commercial utility margin	101.5	93.9	86.3
Total utility margin	$334.2	$321.6	$306.4

2014 COMPARED TO 2013. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes decreased 51.0 million therms, or 8%, primarily reflecting 13% warmer weather, which was partially offset by customer growth and a record February cold weather event;
- operating revenues decreased $0.8 million, due to the 8% decrease in sales volumes, which was partially offset by a 4% increase in average gas rates over last year; and
- utility margin increased $12.6 million, or 4%, primarily related to customer growth, added loads under higher commercial rate schedules, and added rate-base returns from our gas reserves and other investments, partially offset by the effect of warmer weather on our

Washington customers and Oregon customers that opted out of the weather normalization mechanism.

2013 COMPARED TO 2012. The primary factors contributing to changes in the residential and commercial markets were as follows:

- sales volumes increased 34.0 million therms, or 5%, primarily reflecting 5% colder weather and customer growth;
-

operating revenues increased $30.9 million, or 5%, due to a 5% increase in sales volumes and $36.2 million of credits from gas cost savings which were applied to customer billings in 2012, partially offset by a 9% decrease in average gas prices, which flowed through the Company's PGA rates; and

- utility margin increased $15.2 million, or 5%, primarily reflecting the following:

a $10.8 million increase related to customer growth and the rate-base return on our gas reserves and other investments; and

a $3.9 million increase related to the timing impacts of changes in fixed monthly charges and decoupling baselines in the 2012 Oregon general rate case.

Partially offsetting these increases was a $1.4 million decrease primarily related to the lower Oregon Authorized ROE of 9.5% from the 2012 general rate case.

Industrial Sales and Transportation

Industrial customers have the option of purchasing sales or transportation services from the utility. Under the sales service, the customer buys the gas commodity from the utility. Under the transportation service, the customer buys the gas commodity directly from a third-party gas marketer or supplier. Our gas commodity cost is primarily a pass-through cost to customers; therefore, our profit margins are not materially affected by an industrial customer's decision to purchase gas from us or from third parties. Industrial and large commercial customers may also select between firm and interruptible service options, with firm services generally providing higher profit margins compared to interruptible services. To help manage gas supplies, our industrial tariffs are designed to provide some certainty regarding industrial customers' volumes by requiring an annual service election, special charges for changes between elections, and in some cases, a minimum or maximum volume requirement before changing options.

Industrial sales and transportation highlights include:

In millions	2014	2013	2012
Volumes (therms):			
Industrial - firm sales	34.0	34.3	34.9
Industrial - firm transportation	153.6	144.5	131.2
Industrial - interruptible sales	76.4	59.5	59.6
Industrial - interruptible transportation	208.1	236.2	248.2
Total volumes	472.1	474.5	473.9
Utility margin:			
Industrial - sales and transportation	$30.0	$28.3	$28.6

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2014 COMPARED TO 2013. The primary factors contributing to changes in the industrial sales and transportation markets were as follows:

- sales and transportation volumes decreased by 2.4 million therms due to lower usage by large volume interruptible transportation customers on lower margin rate schedules;
- utility margin increased $1.6 million, or 6% primarily due to volume growth under higher margin rate schedules and other customer charges stemming from the extreme cold weather event in February 2014.

2013 COMPARED TO 2012. The primary factors contributing to changes in the industrial sales and transportation markets were as follows:

- sales volumes remained relatively flat for 2013 compared to 2012; and
- utility margin decreased 1%, primarily due to lower demand from customers in the pulp and paper segment. These decreases were partially offset by contributions from new customers and added load from existing customers.

Other Revenues

Other revenues include miscellaneous fee income as well as regulatory revenue adjustments, which reflect current period deferrals to and prior year amortizations from regulatory asset and liability accounts, except for gas cost deferrals which flow through cost of gas. Decoupling amortizations and other regulatory amortizations from prior year deferrals are included in revenues from residential, commercial and industrial firm customers.

Other revenue highlights include:

In millions	2014	2013	2012
Other revenues	$4.0	$4.1	$5.9

2014 COMPARED TO 2013. Other revenues remained relatively flat year over year.

2013 COMPARED TO 2012. The primary factors contributing to changes in other revenues were as follows:

- other revenues decreased $1.9 million primarily due to a positive 2012 regulatory adjustment which did not reoccur in 2013.

Cost of Gas

Cost of gas as reported by the utility includes gas purchases, gas withdrawn from storage inventory, gains and losses from commodity hedges, pipeline demand costs, seasonal demand cost balancing adjustments, regulatory gas cost deferrals, gas reserve costs, and company gas use. The OPUC and WUTC generally require natural gas commodity costs to be billed to customers at the actual cost incurred, or expected to be incurred, by the utility. Customer rates are set each year so that if cost estimates were met we would not earn a profit or incur a loss on gas commodity purchases; however, in Oregon we have an incentive sharing mechanism whereby we either increase or decrease margin results based on a percentage of actual gas costs as compared to embedded gas costs in the PGA. Under this provision, our net income can be affected by differences between actual and expected gas costs, which occur

primarily because of market fluctuations and volatility affecting unhedged gas purchases in the PGA. In addition, we have a regulatory agreement where we earn a rate-base return on our investment in gas reserves, which is reflected in utility margin. See "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment and Gas Reserves" above.

We use natural gas commodity hedge contracts (derivative instruments), primarily fixed-price commodity swaps, consistent with our financial derivatives policies to help manage gas price stability. Gains and losses from these financial hedge contracts are generally included in our PGA and normally do not impact net income because the hedged prices are reflected in our annual PGA rates, subject to a regulatory prudence review. However, hedge contracts entered into after the annual PGA rates are set for Oregon customers can impact net income because we would be required to share in any gains or losses as compared to the corresponding commodity prices built into rates in the PGA. In Washington, 100% of the actual gas costs, including hedge gains and losses allocated to Washington gas sales, are passed through in customer rates. See "Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities" below, "Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment" above, and Note 13.

Cost of gas highlights include:

Dollars and therms in millions	2014	2013	2012
Cost of gas	$365.5	$373.3	$355.3
Volumes sold (therms)	716	766	732
Average cost of gas (cents per therm)	$0.51	$0.49	$0.54
Gain (loss) from gas cost incentive sharing	(2.1)	—	3.8

2014 COMPARED TO 2013. The primary factors contributing to changes in cost of gas were as follows:

- cost of gas decreased $7.8 million, or 2% primarily due to a 7% decrease in sales volume reflecting warmer weather during the year, partially offset by a 4% increase in average cost of gas collected through rates.

2013 COMPARED TO 2012. The primary factors contributing to changes in cost of gas were as follows:

- cost of gas increased $18.0 million, or 5%, including the $37.7 million of credits applied to customer billings in 2012 related to the refund of gas cost savings. Excluding the customer credits, total cost of gas decreased $19.7 million, or 5%, primarily due to a 5% increase in volumes offset by a 9% decrease in average cost of gas collected through rates, reflecting lower market prices for natural gas.

During the first quarter of 2014, many parts of the United States experienced record cold weather for an extended period, while the Pacific Northwest temperatures were closer to normal averages. The extreme cold weather in early 2014 resulted in significant withdrawals of gas from storage and higher gas prices compared to 2013. In early February 2014, the Pacific Northwest had extreme cold weather for a few days that resulted in a record sendout for

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our utility. Consequently, higher volumes of gas purchases and higher gas prices during this period resulted in a margin loss of $2.1 million for 2014 under our gas cost incentive sharing mechanism. The effect on net income from our gas cost incentive sharing mechanism for 2013 was a pre-tax gain in margin of less than $0.1 million, compared to a pre-tax gain of $3.8 million for 2012. For a discussion of our gas cost incentive sharing mechanism, see “Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment” above.

Business Segments - Gas Storage

Our gas storage segment primarily consists of the non-utility portion of our Mist underground storage facility in Oregon and our 75% ownership interest in the Gill Ranch underground storage facility in California.

At Mist, we provide gas storage services to customers in the interstate and intrastate markets primarily using storage capacity that has been developed in advance of core utility customers’ requirements. We also contract with an independent energy marketing company to provide asset management services using our utility and non-utility storage and transportation capacity, the results of which are included in the gas storage businesses segment. Pre-tax income from gas storage at Mist and asset management services using our utility's storage and transportation capacity is subject to revenue sharing with core utility customers. Under this regulatory incentive sharing mechanism, we retain 80% of pre-tax income from Mist gas storage services and asset management services when the underlying costs of the capacity being used are not included in our utility rates, and 33% of pre-tax income from such storage and asset management services when the capacity being used is included in utility rates. The remaining 20% and 67%, respectively, are credited to a deferred regulatory account for credit to our core utility customers. See "Regulatory Matters—Open Regulatory Proceedings" above for information regarding an open docket related to this incentive sharing mechanism.

Our 75% undivided ownership interest in the Gill Ranch facility is held by our wholly-owned subsidiary Gill Ranch, LLC, which is also the operator of the facility. Our portion of the facility is 15 Bcf of gas storage capacity. Gill Ranch commenced operations at the end of 2010, with the first full storage injection season beginning on April 1, 2011. We also contract with an independent energy marketing company to provide asset management services at Gill Ranch. See Note 4.

Gas storage segment highlights include:

In millions, except EPS data	2014		2013	2012
Gas storage net income	$(0.4	)	$5.6	$4.5
EPS - gas storage segment	(0.01	)	0.21	0.17
Operating revenue	22.2		31.1	30.5
Operating expense	18.2		16.4	17.3

2014 COMPARED TO 2013. Our gas storage segment net income decreased $5.9 million primarily due to the following factors:

- an $8.9 million decrease in operating revenues, primarily reflecting recontracting expiring storage

capacity at lower prices as the gas storage market prices remain at historic lows; and

- a $1.8 million increase in operating expenses primarily due to higher repair and power costs at our Gill Ranch facility. See additional information regarding these expense trends below.

2013 COMPARED TO 2012. Our gas storage segment net income increased $1.0 million primarily due to higher revenues from asset management services and lower operating costs.

Over the past few years, market prices for natural gas storage, particularly in California, were negatively affected by the abundant supply of natural gas, low volatility of natural gas prices, and surplus gas storage capacity. In addition, storage prices were further affected by extreme cold weather this past winter, which resulted in a significant decline in storage levels, a rise in spot gas prices, and lower storage values due to a flatter forward price curve for the 2014-15 gas storage year. We re-contracted certain expiring storage capacity for the 2014-15 gas storage year with shorter-term contracts at substantially lower market prices than in previous years. These trends accounted for most of the decline in gas storage operating revenues.

We incurred an additional $2.4 million of repair and power costs at Gill Ranch during 2014 compared to 2013. The increase in power costs is primarily due to higher injections into storage during 2014 to replenish low storage levels following higher withdrawals during the 2013-14 winter. The additional repair costs were for maintenance work at the Gill Ranch facility, which has now been in operation for three annual cycles. We are continuing to evaluate potential capital improvements that may be needed to enhance the operations of the facility. See "Financial Condition—Liquidity and Capital Resources" and "Financial Condition—Cash Flows—Investing Activities" for more information below.

Our gas storage segment financial results have been negatively impacted in the short term by the decline in market conditions and higher than normal repair costs incurred this year. Despite these conditions, we continue to believe in the long-term need for gas storage in California and have recently seen a slight increase in contracting prices. In the future, we anticipate a rebound in gas storage values and an increase in the demand for natural gas driven by a number of factors, including changes in electric generation triggered by California's renewable portfolio standards, increase in use of alternative fuels to meet carbon reduction targets, recovery of the California economy, growth of domestic industrial manufacturing, potential exports of liquefied natural gas from the West Coast, and other favorable market conditions in and around California. These factors would likely result in higher summer/winter natural gas price spreads, gas price volatility, and gas storage values. Refer to Note 2 for more information regarding our accounting for impairment of long-lived assets.

Other

Other primarily consists of NNG Financial's equity investment in KB Pipeline, an equity investment in TWH, which in turn has invested in the Trail West pipeline project, and other miscellaneous non-utility investments and

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business activities. See Note 4 and Note 12 for further details on other activities and our investment in TWH.

Other highlights include:

In millions, except EPS data	2014	2013	2012
Other net income	$0.5	$—	$0.2
EPS - other	0.02	—	—

2014 COMPARED TO 2013. Other net income increased $0.5 million primarily due to increased merchandise sales from our natural gas appliance store.

2013 COMPARED TO 2012. Other net income remained relatively flat, as anticipated.

Consolidated Operations

Operations and Maintenance

Operations and maintenance highlights include:

In millions	2014	2013	2012
Operations and maintenance	$137.0	$136.6	$129.5

2014 COMPARED TO 2013. Operations and maintenance expense increased $0.4 million, primarily due to the following factors:

- a $2.4 million increase from additional repair and power costs at our Gill Ranch storage facility;
- a $1.5 million increase in professional service costs related to our ongoing growth initiatives;
- a $0.4 million increase in bad debt expense at the utility due to lower comparable amounts in 2013 driven by a decrease in our allowance for uncollectible accounts in the first quarter of 2013; and
- Partially offsetting the above factors was a $3.9 million decrease in utility payroll and other costs.

2013 COMPARED TO 2012. Operations and maintenance expense increased $7.1 million, or 6%, primarily due to the following factors:

- a $5.9 million increase in utility payroll expense primarily related to additional customer service positions for new programs and higher incentive compensation; and
- a $2.7 million increase in utility expenses related to system maintenance and safety program costs.

Partially offsetting the above factors were:

- a $0.9 million decrease in utility bad debt expense. See further discussion below.

Delinquent customer receivable balances have remained low for several years despite challenging economic conditions during the recession. This sustained, favorable trend resulted in a decrease to our allowance for uncollectible accounts in the first quarter of 2013, and bad debt expense continues to remain at historically low levels for the Company. The utility's bad debt expense as a percent of revenues was 0.1% for 2014 and has remained well below 0.5% of revenues every year since 2007.

In addition to fluctuations in operation and maintenance expense reported above, we have OPUC approval to defer certain utility pension costs in excess of what is currently recovered in customer rates. This pension cost deferral is recorded to a regulatory balancing account, which stabilizes the amount of operations and maintenance expense each year. For the year ended December 31, 2014 and 2013 we deferred pension expenses totaling $4.6 million and $9.1 million, respectively. As a result, increased pension costs had a minimal effect on operations and maintenance expense in 2014 and 2013, with the increase principally related to the costs allocated to our Washington operations, which are not covered by the pension balancing account. For further explanation of the pension balancing account, see Note 8 and "Regulatory Matters—Rate Mechanisms—Pension Cost Deferral and Prepaid Pension Assets," above for further explanation of the pension balancing account.

Depreciation and Amortization

Depreciation and amortization highlights include:

In millions	2014	2013	2012
Depreciation and amortization	$79.2	$75.9	$73.0

2014 COMPARED TO 2013. Depreciation and amortization expense increased by $3.3 million due to an increase in utility depreciation expense from system investments, resource center improvements, and gas storage facilities enhancements.

2013 COMPARED TO 2012. Depreciation and amortization expense for 2013 increased by $2.9 million compared to 2012 due to an increase in utility depreciation expense on investments in utility plant for system improvements and training facilities.

Other Income and Expense, Net

Other income and expense, net highlights include:

In millions	2014	2013	2012
Gains from company-owned life insurance	$2.0	$2.5	$2.3
Interest income	0.1	0.1	0.2
Loss on sale of investments	—	—	(0.2)
Loss from equity investments	(0.2)	(0.1)	—
Net interest on deferred regulatory accounts	2.4	4.5	3.0
Other non-operating	(2.4)	(2.3)	(2.1)
Total other income and expense, net	$1.9	$4.7	$3.2

2014 COMPARED TO 2013. Other income and expense, net decreased $2.7 million primarily due to lower interest income on net deferred regulatory balances as a result of insurance proceeds credited to regulatory balances for environmental costs. Our regulatory environmental deferred cost account subject to interest accruals changed from a net regulatory asset balance of $56 million at December 31, 2013 to a net regulatory liability balance of approximately $30 million at December 31, 2014 due to insurance proceeds received in 2014 exceeding amounts spent.

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2013 COMPARED TO 2012. Other income and expense, net increased $1.5 million primarily due to interest on higher average regulatory account balances.

Interest Expense, Net

Interest expense, net highlights include:

In millions	2014	2013	2012
Interest expense, net	$44.6	$45.2	$43.2

2014 COMPARED TO 2013. Interest expense, net of amounts capitalized, decreased $0.6 million primarily due to the redemptions of debt in 2014 of $50 million of utility FMBs in July 2014 and $10 million in September 2014, and the retirement of $20 million of debt pursuant to Gill Ranch's amended loan agreement in June 2014.

2013 COMPARED TO 2012. Interest expense, net of amounts capitalized, increased $2.0 million primarily due to an increase of $2.3 million at the utility from the issuance of long-term debt. The utility issued $50 million of debt with a coupon rate of 3.542% in August 2013 and $50 million of debt with a coupon rate of 4.00% in October 2012. This increase was partially offset by a $0.7 million reduction in 2013 interest expense at the utility from the retirement of $40 million of long-term debt with a coupon rate of 7.13% in 2012. See Note 7 for further detail.

Income Tax Expense

Income tax expense highlights include:

In millions	2014		2013		2012	
Income tax expense	$41.6		$41.7		$43.4	
Effective tax rate	41.5	%	40.8	%	42.5	%

2014 COMPARED TO 2013. The increase in the effective income tax rate was primarily the result of a $0.6 million income tax charge in 2014 related to a higher statutory tax rate in Oregon, which required the revaluation of deferred tax balances.

2013 COMPARED TO 2012. The decrease in income tax expense of $1.7 million or 4% was primarily due to a $2.7 million tax charge taken in 2012 from an Oregon general rate case disallowance.

FINANCIAL CONDITION

Capital Structure

One of our long-term goals is to maintain a strong consolidated capital structure, generally consisting of 45% to 50% common stock equity and 50% to 55% long-term and short-term debt, and with a target utility capital structure of 50% common stock and 50% long-term debt. When additional capital is required, debt or equity securities are issued depending on both the target capital structure and market conditions. These sources of capital are also used to fund long-term debt retirements and short-term commercial paper maturities. See "Liquidity and Capital Resources" below and Note 7.

Achieving the target capital structure and maintaining sufficient liquidity to meet operating requirements are necessary to maintain attractive credit ratings and provide access to capital markets at reasonable costs. Our consolidated capital structure was as follows:

	December 31,			
	2014		2013	
Common stock equity	46.1	%	44.7	%

Long-term debt	37.4	40.5
Short-term debt, including current maturities of long-term debt	16.5	14.8
Total	100.0 %	100.0 %

Liquidity and Capital Resources

At both December 31, 2014 and 2013 we had $9.5 million of cash and cash equivalents. We also had $3.0 million and $4.0 million in restricted cash at Gill Ranch as of December 31, 2014 and 2013, respectively. This restricted cash is being held as collateral for the long-term debt outstanding. In order to maintain sufficient liquidity during periods when capital markets are volatile, we may elect to maintain higher cash balances and add short-term borrowing capacity. In addition, we may also pre-fund utility capital expenditures when long-term fixed rate environments are attractive. As a regulated entity, our issuance of equity securities and most forms of debt securities are subject to approval by the OPUC and WUTC. Our use of retained earnings is not subject to those same restrictions.

For the utility segment, the short-term borrowing requirements typically peak during colder winter months when the utility borrows money to cover the lag between natural gas purchases and bill collections from customers. Our short-term liquidity for the utility is primarily provided by cash balances, internal cash flow from operations, proceeds from the sale of commercial paper notes, as well as available cash from multi-year credit facilities, company-owned life insurance policies, and the sale of long-term debt. Utility long-term debt proceeds are primarily used to finance utility capital expenditures, refinance maturing debt of the utility, and provide temporary funding for other general corporate purposes of the utility.

Based on our current debt ratings (see "Credit Ratings" below), we have been able to issue commercial paper and long-term debt at attractive rates and have not needed to borrow or issue letters of credit from our back-up credit facility. In the event we are not able to issue new debt due to adverse market conditions or other reasons, we expect our near term liquidity needs can be met using internal cash flows or, for the utility segment, drawing upon our committed credit facility. We also have a universal shelf registration filed with the SEC for the issuance of secured and unsecured debt or equity securities, subject to market conditions and certain regulatory approvals. As of December 31, 2014, we have Board authorization to issue up to $325 million of additional FMB's. We also have OPUC approval to issue up to $325 million of additional long-term debt for approved purposes.

In the event our senior unsecured long-term debt ratings are downgraded, or our outstanding derivative position exceeds a certain credit threshold, our counterparties under derivative contracts could require us to post cash, a letter of credit, or other forms of collateral, which could expose us to additional cash requirements and may trigger increases in short-term borrowings while we were in a net loss position. We were not near the threshold for posting collateral at December 31, 2014. However, if the credit risk-related contingent features underlying these contracts were triggered on December 31, 2014, assuming our long-term debt ratings dropped to non-investment grade levels, we could have been required to post $27.1 million of collateral to our counterparties. See "Credit Ratings" below and Note 13.

Other recent developments that may have a significant impact on our liquidity and capital resources include pension contribution requirements, income tax benefits from bonus depreciation, environmental expenditures and insurance recoveries.

With respect to pensions, we expect to make significant contributions to our company-sponsored defined benefit plan, which is closed to new employees, over the next several years until we are fully funded under the Pension Protection Act rules, including the new rules issued under the Moving Ahead for Progress in the 21st Century Act (MAP-21) and the Highway and Transportation Funding Act of 2014 (HATFA). See "Application of Critical Accounting Policies—Accounting for Pensions and Postretirement Benefits" below.

Regarding income tax, 50 percent bonus depreciation was available for a large portion of our capital expenditures in 2012, 2013, and 2014 for both federal and Oregon. This generated income tax net operating losses (NOLs) in 2012 and 2013, and reduced taxable income in 2014. This provided cash flow benefits and is expected to provide cash flow benefits in subsequent years while NOLs from these periods are utilized. The Company estimates that it has income tax NOL carryforwards of $28.8 million for federal and $49.4 million for Oregon at December 31, 2014.

Concerning environmental expenditures, we expect to continue using cash resources to fund our environmental liabilities. In 2014, we received insurance settlements in excess of amounts spent and will begin recovering amounts through utility rates under the SRRM in 2015. These expenditures are uncertain as to the amount and timing. See Note 15, Note 16, and "Results of Operations—Regulatory Matters—Environmental Costs".
Short-term liquidity for the gas storage segment is supported by cash balances, internal cash flow from operations, external financing, and funds from its parent company. The abundant supply of natural gas, low volatility of natural gas prices, and available gas storage capacity, particularly in California, have recently resulted in lower storage market prices than we have seen in previous years.

The amount and timing of our Gill Ranch facility's cash flows from year to year are uncertain, as the majority of these storage contracts are currently short term. We contracted for the 2014-15 gas year at lower prices than the prior year and have realized higher repairs and power costs in 2014. Both factors contributed to negative cash flows from operations for 2014. We expect continuing challenges for Gill Ranch in 2015, however, we have seen improvement in pricing for the upcoming 2015-16 gas storage year. Though prices are still lower than our long-term contracts that expired during the 2013-14 gas storage year. We do not anticipate material changes in our ability to access sources of cash for short-term liquidity.

In November 2011, Gill Ranch issued $40 million of senior secured debt, with a fixed interest rate of 7.75% on $20 million and a variable interest rate on the remaining $20 million, with an original maturity date of November 30, 2016. Under the debt agreement, Gill Ranch is subject to certain covenants and restrictions. We amended the original agreement in April 2014 to retire the $20 million variable-rate outstanding debt during the second quarter of 2014 and suspend the EBITDA covenant requirement through March 31, 2015 with lower EBITDA hurdles thereafter. The amendment fixed the debt service reserve at $3 million. Gill Ranch retired $20 million of debt on June 6, 2014 using available cash and cash flows from operations, including cash from intercompany receivables. The remaining $20 million of outstanding debt is secured by all of the membership interests in Gill Ranch and is nonrecourse to NW

Natural and other entities of the consolidated group. We do not anticipate meeting the adjusted covenant requirements in 2015 and are working with our lender to negotiate an extension of the covenants or early redemption of the debt.

Based on several factors, including our current credit ratings, our commercial paper program, current cash reserves, committed credit facilities, and our expected ability to issue long-term debt in the capital markets, we believe the Company's liquidity is sufficient to meet anticipated near-term cash requirements, including all contractual obligations, investing, and financing activities discussed below.

Dividend Policy

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

Off-Balance Sheet Arrangements

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

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Contractual Obligations

The following table shows our contractual obligations at December 31, 2014 by maturity and type of obligation:

	Payments Due in Years Ending December 31,						
In millions	2015	2016	2017	2018	2019	Thereafter	Total
Commercial paper	$234.7	$—	$—	$—	$—	$—	$234.7
Long-term debt maturities	40.0	45.0	40.0	22.0	30.0	484.7	661.7
Interest on long-term debt	36.9	35.7	32.1	29.2	28.6	201.9	364.4
Postretirement benefit payments[1]	22.7	23.5	24.3	25.4	26.8	156.4	279.1
Capital leases	0.7	0.6	0.1	—	—	—	1.4
Operating leases	5.5	5.5	5.4	5.3	5.2	29.8	56.7
Gas purchases[2]	132.4	—	—	—	—	—	132.4
Gas pipeline capacity commitments	84.3	79.2	58.8	50.8	26.7	205.3	505.1
Other purchase commitments[3]	0.1	—	—	—	—	13.6	13.7
Other long-term liabilities[4]	16.2	—	—	—	—	—	16.2
Total	$573.5	$189.5	$160.7	$132.7	$117.3	$1,091.7	$2,265.4

(1) Postretirement benefit payments primarily consists of two items: (1) estimated qualified defined benefit pension plan payments, which are funded by plan assets and future cash contributions, and (2) required payments to the Western States multiemployer pension plan due to the Company withdrawing from the plan in December 2013. See Note 8.

(2) Gas purchases include contracts which use price formulas tied to monthly index prices, plus hedged derivative liabilities. Commitment amounts are based on futures prices as of December 31, 2014. For a summary of derivatives, see Note 13. For a summary of gas purchase and gas pipeline capacity commitments, see Note 14.

(3) Other purchase commitments primarily consist of base gas requirements and remaining balances under existing purchase orders.

(4) Other long-term liabilities includes accrued vacation liabilities for management employees and deferred compensation plan liabilities for executives and directors. The timing of these payments are uncertain; however, these payments are unlikely to all occur in the next 12 months.

In addition to known contractual obligations listed in the above table, we have also recognized liabilities for future environmental remediation or action. The exact timing of payments beyond 12 months with respect to those liabilities cannot be reasonably estimated due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of site investigations. See Note 15 for a further discussion of environmental remediation cost liabilities.

At December 31, 2014, 612 of our utility employees were members of the Office and Professional Employees International Union (OPEIU) Local No. 11. On May 22, 2014, our union employees ratified a new labor agreement (Joint Accord) that expires on November 30, 2019. The Joint Accord includes the following items: an average annualized compensation increase of 4% effective June 1, 2014, which includes a 7.9% wage increase to better reflect current market competitive wages, offset by a reduction in bonus pay opportunities for union employees; and a scheduled 3% wage increase effective December 1 each year thereafter, beginning in 2015 with the potential for up to an additional 3% per year based on wage inflation at or above 4%. The Joint Accord also maintains competitive health benefits, including a 15% to 20% premium cost sharing by employees, job flexibility, and other flexibility provisions for the Company.

Short-Term Debt

Our primary source of utility short-term liquidity is from internal cash flows and the sale of commercial paper. In addition to issuing commercial paper to meet working capital requirements, including seasonal requirements to finance gas purchases and accounts receivable, short-term debt may also be used to temporarily fund utility capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our outstanding commercial paper, which is sold through two commercial banks under an issuing and paying agency agreement, is supported by one or more unsecured revolving credit facilities. See "Credit Agreements" below. At December 31, 2014 and 2013, our utility had commercial paper outstanding of $234.7 million and $188.2 million, respectively. The effective interest rate on the utility's commercial paper outstanding at December 31, 2014 and 2013 was 0.4% and 0.3%, respectively.

Credit Agreements

On December 20, 2012, NW Natural entered into a five-year $300 million credit agreement, with a feature that allows the Company to request increases in the total commitment amount, up to a maximum of $450 million. The credit agreement also permits an extension of the commitments for two additional one-year periods, subject to lender approval. The Company exercised the first of these extensions in December 2013, and the second in December 2014 with a final maturity date of December 20, 2019.

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All lenders under the new agreement are major financial institutions with committed balances and investment grade credit ratings as of December 31, 2014 as follows:

In millions	
Lender rating, by category	Loan Commitment
AA/Aa	$234
A/A	66
BBB/Baa	—
Total	$300

Based on credit market conditions, it is possible one or more lending commitments could be unavailable to us if the lender defaulted due to lack of funds or insolvency; however, the Company does not believe this risk to be imminent due to the lenders' strong investment-grade credit ratings.

In December 2014, the Company amended the credit agreement to reduce the permitted letter of credit amount from $200 million to $100 million. Any principal and unpaid interest amounts owed on borrowings under the credit agreements is due and payable on or before the maturity date. There were no outstanding balances under this credit agreement at December 31, 2014 or 2013. The credit agreement requires us to maintain a consolidated indebtedness to total capitalization ratio of 70% 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, 2014 and 2013, with consolidated indebtedness to total capitalization ratios of 53.9% and 55.3%, respectively.

The agreement also requires us to 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 or senior secured debt
ratings, as applicable, by such rating agencies. A change in our debt ratings by S&P or Moody's is not an event of default, nor is the maintenance of a specific minimum level of debt rating a condition of drawing upon the credit agreement. Rather, interest rates on any loans outstanding under the credit agreements are tied to debt ratings and therefore, a change in the debt rating would increase or decrease the cost of any loans under the credit agreements when ratings are changed. See "Credit Ratings" below.

Credit Ratings

Our credit ratings are a factor of our liquidity, potentially affecting our access to the capital markets including the commercial paper market. Our credit ratings also have an impact on the cost of funds and the need to post collateral under derivative contracts. The following table summarizes our current debt ratings from S&P and Moody's:

	S&P	Moody's
Commercial paper (short-term debt)	A-1	P-2
Senior secured (long-term debt)	AA-	A1
Senior unsecured (long-term debt)	n/a	A3
Corporate credit rating	A+	n/a
Ratings outlook	Stable	Stable

The above credit ratings are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of or reference to these credit ratings is not a recommendation to buy, sell or hold NW Natural securities. Each rating should be evaluated independently of any other rating.

Maturity and Redemption of Long-Term Debt

The following debentures were retired:

	Years Ended December 31,		
In millions	2014	2013	2012
Utility First Mortgage Bonds			
7.13% Series B due 2012	$—	$—	$40
3.95% Series B due 2014	50	—	—
8.26% Series B due 2014	10	—	—
	60	—	40
Subsidiary Debt			
Variable-rate	20	—	—
	$80	$—	$40

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Cash Flows

Operating Activities

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.

Operating activity highlights include:

In millions	2014	2013	2012
Cash provided by operating activities	$215.7	$176.4	$168.8

2014 COMPARED TO 2013. The significant factors contributing to the $39.3 million increase in operating cash flows were as follows:

- an increase of $105.5 million in deferred environmental recoveries, net of expenditures reflecting the receipt of insurance settlements during 2014;
- an increase of $41.0 million from changes in the accounts receivable balance, primarily due to colder weather in December 2013.
- a decrease of $24.1 million from changes in inventory balances due to refilling gas storage inventory after colder weather in December 2013;
- a decrease of $48.1 million from changes in regulatory balances, an increase in pension liabilities, and an increase in prepaids;
- a decrease of $21.7 million in deferred taxes due to the utilization of NOL carryforwards; and
- a decrease of $17.9 million from changes in deferred gas costs balances, which reflected higher actual gas prices than prices embedded in the PGA compared to the prior year.

2013 COMPARED TO 2012. The significant factors contributing to the $7.6 million increase in operating cash flows were as follows:

- an increase of $15.8 million in other, net primarily due to inflows from changes in net regulatory balances offset by a decrease in pension liabilities;
- an increase of $12.4 million from net changes in gas cost balances, which primarily reflects $39 million in credits refunded to customers in 2012;
- an increase of $11.8 million due to lower cash contributions to qualified defined benefit pension plans as a result of new IRS funding rules, commonly referred to as MAP-21;
- an increase of $8.0 million from changes in accounts payable balances; and
- an increase of $4.7 million due to changes in the amortization of gas reserves balance.

Partially offsetting these increases was:

- a decrease of $48.3 million from changes in the accounts receivable balance, primarily due to customer growth and 29% colder weather in December 2013.

During the year ended December 31, 2014, we contributed $10.5 million to our utility's qualified defined benefit pension plan, compared to $11.7 million for 2013. We expect contribution amounts in the near-term will be less than previously anticipated due to the federal funding requirements under MAP-21 and HATFA. The amounts and timing of future contributions will depend on market interest

rates and investment returns on the plans’ assets. See Note 8.

Bonus depreciation of 50 percent has been available for federal and Oregon purposes in 2012, 2013, and 2014. This generated income tax NOLs in 2012 and 2013, and reduced taxable income in 2014. This provided cash flow benefits in 2012 and 2013 and is expected to provide cash flow benefits in subsequent years while NOL carryforwards from these periods are utilized. Bonus depreciation for 2014 was not enacted until December of 2014, when it was extended retroactively back to January 1, 2014. As a result, estimated income tax payments were made throughout 2014 without the benefit of bonus depreciation for the year. This reduced the cash flow benefit of bonus depreciation in 2014 and contributed to the prepaid income tax balance of $6.7 million and income tax receivable balance of $1.0 million, as of December 31, 2014.

We have lease and purchase commitments relating to our operating activities that are financed with cash flows from operations. For information on cash flow requirements related to leases and other purchase commitments, see "Financial Condition—Contractual Obligations" above and Note 14.

Investing Activities

Investing activity highlights include:

In millions	2014	2013	2012
Total cash used in (provided by) investing activities	$144.3	$182.1	$184.7
Capital expenditures	120.1	138.9	132.0
Proceeds from sale of assets	(0.2)	(8.6)	—
Utility gas reserves	26.8	54.1	54.1

2014 COMPARED TO 2013. The $37.8 million decrease in cash used in investing activities was primarily due to lower investments in capital expenditures and utility gas reserves as NW Natural ended its original drilling program with Encana in 2014. See Note 11.

2013 COMPARED TO 2012. The $2.5 million decrease in cash used in investing activities was due to proceeds received from the sale of assets. This decrease was partially offset by higher capital expenditures, reflecting increased investments for new customer acquisitions, completion of our Gasco Source Control water treatment station, and additional expenditures for system integrity and bare steel pipe removal.

Over the five-year period 2015 through 2019, total utility capital expenditures are estimated to be between $850 and $950 million, including the Company's proposed investment in an expansion of our Mist gas storage facility. The estimated level of utility capital expenditures over the next five years reflects assumptions for continued customer growth, technology, distribution system improvements, and gas storage facilities. Most of the required funds are expected to be internally generated over the five-year period, and any remaining funding will be obtained through a combination of long-term debt and equity security issuances, with short-term debt providing liquidity and bridge financing.

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In 2015, utility capital expenditures are estimated to be between $140 and $150 million, and non-utility capital investments are estimated to be less than $10 million. Gas storage segment capital expenditures in 2015 are expected to be paid from working capital and additional equity contributions from NW Natural as needed.

Financing Activities

Financing activity highlights include:

In millions	2014	2013	2012
Total cash provided by (used in) financing activities	$(71.3)	$6.3	$18.9
Change in short-term debt	46.5	(2.1)	48.7
Change in long-term debt	(80.0)	50.0	10.0

2014 COMPARED TO 2013. The $77.6 million decrease in cash provided by financing activities was primarily due to using the proceeds from our insurance settlements of $103 million to redeem $60 million of long-term utility debt. In addition, Gill Ranch retired $20 million of variable interest rate debt.

2013 COMPARED TO 2012. The $12.6 million decrease in cash provided by financing activities was primarily due to changes in our short-term debt balances, which decreased $2.1 million in 2013 compared to an increase of $48.7 million in 2012. This decrease was partially offset by changes in our long-term debt balances due to $40 million of long-term debt retired in 2012. We continue to use long-term debt proceeds to finance capital expenditures, refinance maturing short-term or long-term debt maturities, and to fund other general corporate purposes.

PENSION COST AND FUNDING STATUS OF QUALIFIED RETIREMENT PLANS. Pension costs are determined in accordance with accounting standards for compensation and retirement benefits. See “Application of Critical Accounting Policies and Estimates – Accounting for Pensions and Postretirement Benefits” below. Pension expense for our qualified defined benefit plan, which is allocated between operation and maintenance expenses, capital expenditures, and the deferred regulatory balancing account, totaled $14.2 million in 2014, a decrease of $7.3 million from 2013. The fair market value of pension assets in this plan increased to $279.2 million at December 31, 2014 from $267.1 million at December 31, 2013. The increase was due to a return on plan assets of $20.0 million plus $10.5 million in employer contributions, partially offset by benefit payments of $18.4 million.

We make contributions to the company-sponsored qualified defined benefit pension plan based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Our qualified defined benefit pension plan was underfunded by $172.0 million at December 31, 2014. We plan to make contributions during 2015 of $15 million. See Note 8 for further pension disclosures.

Ratios of Earnings to Fixed Charges

For the years ended December 31, 2014, 2013, and 2012, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission (SEC) method, were 3.13, 3.16, and 3.26, respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income. See Exhibit 12 for the detailed ratio calculation.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. See “Application of Critical Accounting Policies and Estimates” below. At December 31, 2014, we had a net regulatory asset of $58.9 million for deferred environmental costs, which included $95.5 million for additional costs expected to be paid in the future and $19.7 million of accrued interest. Additionally, in 2014, a settlement was reached in our environmental insurance recovery litigation, and NW Natural received $103 million in recoveries for a cumulative total of approximately $150 million. The regulatory asset for deferred environmental costs is calculated net of insurance reimbursements. In February 2015, the OPUC issued an order regarding the Site Remediation and Recovery Mechanism (SRRM) for recovering prudently incurred environmental site remediation costs through customer billings, subject to an earnings test. The order applied an earnings test to a historical period 2003 through 2012 that resulted in a regulatory disallowance of $15 million pre-tax to be recorded in the first quarter of 2015. See Note 15, Note 16, and "Results of Operations—Regulatory Matters—Rate Mechanisms—Environmental Costs" above.

New Accounting Pronouncements

For a description of recent accounting pronouncements that may have an impact on our financial condition, results of operations or cash flows, see Note 2.

APPLICATION OF CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

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

Management has discussed its current estimates and judgments used in the application of critical accounting policies with the Audit Committee of the Board. Within the context of our critical accounting policies and estimates, Management is not aware of any reasonably likely events or circumstances that would result in materially different amounts being reported. For a description of recent accounting pronouncements that could have an impact on our financial condition, results of operations or cash flows, see Note 2.

Regulatory Accounting

Our utility is regulated by the OPUC and WUTC, which establish the rates and rules governing utility services provided to customers, and, to a certain extent, set forth special accounting treatment for certain regulatory transactions. In general, we use the same accounting principles as non-regulated companies reporting under GAAP. However, authoritative guidance for regulated operations (regulatory accounting) requires 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—Purchased Gas Adjustment" above. There are other expenses and revenues that the OPUC or WUTC may require us to defer for recovery or refund in future periods. Regulatory accounting requires us to account for these types of deferred expenses (or deferred revenues) as regulatory assets (or regulatory liabilities) on the balance sheet. When we are allowed to recover these regulatory assets from, or are required to refund regulatory liabilities to, customers, we recognize the expense or revenue on the income statement at the same time we realize the adjustment to amounts included in utility rates charged to customers.

The conditions we must satisfy to adopt the accounting policies and practices of regulatory accounting include:

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

Because our utility satisfies all three conditions, we continue to apply regulatory accounting to our utility operations. Future accounting changes, regulatory changes or changes in the competitive environment could require us to discontinue the application of regulatory accounting for some or all of our regulated businesses. This would require the write-off of those regulatory assets and liabilities that would no longer be probable of recovery from or refund to customers.

Based on current accounting and regulatory competitive conditions, we believe it is reasonable to expect continued application of regulatory accounting for our utility activities. Further, it is reasonable to expect the recovery or refund of our regulatory assets and liabilities at December 31, 2014 through future customer rates. If we should determine all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of regulatory accounting, then we would be required to write-off the net unrecoverable balances against earnings in the period such determination is made. The net balance in regulatory asset and liability accounts as of December 31, 2014 and 2013 was $101.2 million and $60.4 million, respectively. See Note 2 "Industry Regulation". See Note 16 for information regarding the resolution of the environmental Site Remediation and Recovery Mechanism (SRRM) in February 2015 and a $15 million pre-tax regulatory disallowance to be recognized in the first quarter of 2015.

Revenue Recognition

Utility and non-utility revenues, which are derived primarily from the sale, transportation, and storage of natural gas, are recognized upon the delivery of gas commodity or services rendered to customers.

Accrued Unbilled Revenue

For a description of our policy regarding accrued unbilled revenue for both the utility and non-utility revenues, see Note 2. The following table presents changes in key metrics if the estimated percentage of unbilled volume at December 31 was adjusted up or down by 1%:

	2014		
In millions	Up 1%	Down 1%	
Unbilled revenue increase (decrease)	$0.6	$(0.6	)
Utility margin increase (decrease)[1]	—	—	
Net income increase (decrease)	—	—	

[1] Includes impact of regulatory mechanisms including decoupling mechanism.

Derivative Instruments and Hedging Activities

Our gas acquisition and hedging policies set forth guidelines for using financial derivative instruments to support prudent risk management strategies. These policies specifically prohibit the use of derivatives for trading or speculative purposes. The accounting rules for determining whether a

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contract meets the definition of a derivative instrument or qualifies for hedge accounting treatment are complex. The contracts that meet the definition of a derivative instrument are recorded on our balance sheet at fair value. If certain regulatory conditions are met, then the derivative instrument fair value is recorded together with an offsetting entry to a regulatory asset or liability account pursuant to regulatory accounting (see Note 2, "Industry Regulation"), and no unrealized gain or loss is recognized in current income. The gain or loss from the fair value of a derivative instrument subject to regulatory deferral is included in the recovery from, or refund to, utility customers in future periods (see "Regulatory Accounting", above). If a derivative contract is not subject to regulatory deferral, then the accounting treatment for unrealized gains and losses is recorded in accordance with accounting standards for derivatives and hedging (see Note 2, "Derivatives" and "Industry Regulation") which is either in current income or in accumulated other comprehensive income (AOCI) under common stock equity on the balance sheet. Our derivative contracts outstanding at December 31, 2014 were measured at fair value using models or other market accepted valuation methodologies derived from observable market data. Our estimate of fair value may change significantly from period-to-period depending on market conditions and prices. These changes may have an impact on our results of operations, but the impact would largely be mitigated due to the majority of our derivative activities being subject to regulatory deferral treatment. For estimated fair value of unrealized gains and losses, see Note 13.

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

In millions	2014	2013	2012
Net utility gain (loss) on:			
Commodity			
Swaps	$10.5	$(11.0)	$(69.5)
Options	—	—	(0.7)
Total net gain (loss) realized	$10.5	$(11.0)	$(70.2)

Realized losses from commodity hedges shown above were recorded as increases to cost of gas and were included in our annual PGA rates.

Pensions and Postretirement Benefits

We maintain a qualified non-contributory defined benefit pension plan, non-qualified supplemental pension plans for eligible executive officers and certain key employees, and other postretirement employee benefit plans covering certain non-union employees. We also have a qualified defined contribution plan (Retirement K Savings Plan) for all eligible employees. Only the qualified defined benefit pension plan and Retirement K Savings Plan have plan assets, which are held in qualified trusts to fund the respective retirement benefits. The qualified defined benefit retirement plan for union and non-union employees was closed to new participants several years ago. These plans are not available to employees at any of our subsidiary companies. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and employees of NW Natural subsidiaries are provided an

enhanced Retirement K Savings Plan benefit. The postretirement Welfare Benefit Plan for non-union employees was also closed to new participants several years ago.

Net periodic pension and postretirement benefit costs (retirement benefit costs) and projected benefit obligations (benefit obligations) are determined using a number of key assumptions including discount rates, rate of compensation increases, retirement ages, mortality rates and an expected long-term return on plan assets. See Note 8. These key assumptions have a significant impact on the pension amounts recorded and disclosed. Retirement benefit costs consist of service costs, interest costs, the amortization of actuarial gains, losses and prior service costs, the expected returns on plan assets and, in part, on a market-related valuation of assets, if applicable. The market-related asset valuation reflects differences between expected returns and actual investment returns, which we recognize over a three-year period or less from the year in which they occur, thereby reducing year-to-year volatility in retirement benefit costs.

Accounting standards also require balance sheet recognition of the overfunded or underfunded status of pension and postretirement benefit plans in AOCI or AOCL, net of tax, based on the fair value of plan assets compared to the actuarial value of future benefit obligations. However, the retirement benefit costs related to our qualified defined benefit pension and postretirement benefit plans are generally recovered in utility rates, which are set based on accounting standards for pensions and postretirement benefit expenses. As such, we received approval from the OPUC to recognize the overfunded or underfunded status as a regulatory asset or regulatory liability based on expected rate recovery, rather than including it as AOCI or AOCL under common equity. See "Regulatory Accounting" above and Note 2, "Industry Regulation".

In 2011, we received regulatory approval from the OPUC and began deferring a portion of our pension expense above or below the amount set in rates to a regulatory balancing account on the balance sheet. At December 31, 2014, the cumulative amount deferred for future pension cost recovery was $32.5 million. The regulatory balancing account includes the recognition of accrued interest on the account balance at the utility's authorized rate of return, with the equity portion of this interest being deferred until amounts are collected in rates.

A number of factors, as discussed above, are considered in developing pension and postretirement benefit assumptions. For the December 31, 2014 measurement date, we reviewed and updated:

- our weighted-average discount rate assumptions for pensions went from 4.73% for 2013 to 3.85% for 2014, and our weighted-average discount rate assumptions for other postretirement benefits went from 4.45% for 2013 to 3.74% for 2014. The new rate assumptions were determined for each plan based on a matching of benchmark interest rates to the estimated cash flows, which reflect the timing and amount of future benefit payments. Benchmark interest rates are drawn from the Citigroup Above Median Curve, which consists of high

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quality bonds rated AA- or higher by S&P or Aa3 or higher by Moody’s;

- our expected annual rate of future compensation increases, which remained unchanged at a range of 3.25% to 5.0%;
- our expected long-term return on qualified defined benefit plan assets, which remained unchanged at a rate of 7.50%;
- our mortality rate assumptions were updated to the new RP 2014 combined tables for the pension and postretirement benefit plans. This assumption is used to calculate life expectancies for participants in the plan. The new RP 2014 tables assume greater life expectancy which increased the projected benefit obligations of the plans; and
- other key assumptions, which were based on actual plan experience and actuarial recommendations.

At December 31, 2014, our net pension liability (benefit obligations less market value of plan assets) for the qualified defined benefit plan increased $76.7 million compared to 2013. The increase in our net pension liability is primarily due to the $88.8 million increase in our pension benefit obligation and an increase of $12.1 million in plan assets. The liability for non-qualified plans increased $7.4 million, and the liability for other postretirement benefits increased $3.3 million in 2014.

We determine the expected long-term rate of return on plan assets by averaging the expected earnings for the target asset portfolio. In developing our expected return, we analyze historical actual performance and long-term return projections, which gives consideration to the current asset mix and our target asset allocation. As of December 31, 2014, the actual annualized returns on plan assets, net of management fees, for the past one-year, five-years, and 10-years were 7.9%, 8.0%, and 5.1%, respectively.

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

Dollars in millions	Change in Assumption	Impact on 2014 Retirement Benefit Costs	Impact on Retirement Benefit Obligations at Dec. 31, 2014
Discount rate:	(0.25)%		
Qualified defined benefit plans		$1.4	$16.3
Non-qualified plans		—	1.0
Other postretirement benefits		0.1	1.0
Expected long-term return on plan assets:	(0.25)		
Qualified defined benefit plans		0.7	N/A

In July 2012, President Obama signed into law the MAP-21 Act. This legislation changed several provisions affecting pension plans, including temporary funding relief and Pension Benefit Guaranty Corporation (PBGC) premium

increases, which reduces the level of minimum required contributions in the near-term but generally increases contributions in the long-run as well as increasing the operational costs of running a pension plan. Prior to the MAP-21 Act, we were using interest rates based on a 24-month average yield of investment grade corporate bonds (also referred to as "segment rate") to calculate minimum contribution requirements. MAP-21 Act established a new minimum and maximum corridor for segment rates based on a 25-year average of bond yields, which is to be used in calculating contribution requirements. In August 2014, HATFA was signed and extends certain aspects of MAP-21 as well as modifies the phase-out periods for the limitations. As a result we anticipate lower contributions over the next five years with contributions increasing thereafter.

Income Taxes

Valuation Allowances

We recognize deferred tax assets to the extent that we believe these assets are more likely than not to be realized. In making such a determination, we consider the available positive and negative evidence, including future reversals of existing taxable temporary differences, projected future taxable income, tax-planning strategies, and results of recent operations. The most significant deferred tax assets currently recorded represent income tax net operating loss carryforwards and alternative minimum tax credits. We have determined that we are more likely than not to realize all recorded deferred tax assets as of December 31, 2014. See Note 9.

Uncertain Tax Benefits

The calculation of our tax liabilities involves dealing with uncertainties in the application of complex tax laws and regulations in the jurisdictions in which we operate. A tax benefit from a material uncertain tax position will only be recognized when it is more likely than not that the position, or some portion thereof, will be sustained upon examination, including resolution of any related appeals or litigation processes, on the basis of the technical merits. The Company participates in the Compliance Assurance Program (CAP) with the Internal Revenue Service (IRS). Under the CAP program the Company works with the IRS to identify and resolve material tax matters before the federal income tax return is filed each year. No reserves for uncertain tax benefits were recorded during 2012, 2013, or 2014. See Note 9.

Regulatory Matters

Regulatory tax assets and liabilities are recorded to the extent we believe they will be recoverable from, or refunded to, customers in future rates. As part of the 2012 Oregon general rate case, the OPUC ruled that we cannot recover deferred amounts that represent the increase in deferred income taxes caused by the 2009 Oregon tax rate change. As a result, we recognized an after-tax charge of $2.7 million in 2012 to write off the regulatory asset related to this rate change. At December 31, 2014 and 2013, we have regulatory income tax assets of $51.8 million and $56.2 million, respectively, representing future rate recovery of deferred tax liabilities resulting from differences in utility plant financial statement and tax basis and utility plant removal costs. These deferred tax liabilities, and the associated regulatory income tax assets, are currently being recovered through customer rates. See Note 2.

Tax Legislation

When significant proposed or enacted changes in income tax rules occur we consider whether there may be a material impact to our financial position, results of operations, cash flows, or whether the changes could materially affect existing assumptions used in making estimates of tax related balances.

The final tangible property regulations applicable to all taxpayers were issued on September 13, 2013 and are generally effective for taxable years beginning on or after January 1, 2014. In addition procedural guidance related to the regulations was issued under which taxpayers may make accounting method changes to comply with the regulations. We have evaluated the regulations and do not anticipate any material impact. However, unit-of-property guidance applicable to natural gas distribution networks has not yet been issued and is expected in 2015. We will further evaluate the effect of these regulations after this guidance is issued, but believe our current method is materially consistent with the new regulations and do not expect these regulations to have a material effect on our financial statements.

The Federal Tax Increase Prevention Act of 2014, signed into law on December 19, 2014, retroactively extended for one year various temporary income tax deductions, credits, and incentives that expired at the end of 2013, including 50 percent bonus depreciation for certain qualifying property placed in service through 2014. See "Financial Conditions—Cash Flows" above.

Environmental Contingencies

We account for environmental liabilities in accordance with accounting standards under the loss contingency guidance when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable. For a complete discussion of our environmental policy see Note 2. For a discussion of our current environmental sites and liabilities see Note 15 and "Contingent Liabilities" above. In addition, for information regarding the regulatory treatment of these costs and our regulatory recovery mechanism, see "Results of Operations—Rate Matters—Rate Mechanisms—Environmental Costs" above.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Supply Risk

We enter into spot, short-term, and long-term natural gas supply contracts, along with associated pipeline transportation contracts, to manage our commodity supply risk. Historically, we have arranged for physical delivery of an adequate supply of gas, including gas in our Mist storage and off-system storage facilities, to meet expected requirements of our core utility customers. Our gas purchase contracts are primarily index-based and subject to

monthly re-pricing, a strategy that is intended to substantially mitigate credit exposure to our physical gas counterparties.

Commodity Price and Storage Value Risk

Natural gas commodity prices and storage values are subject to market fluctuations due to unpredictable factors including weather, pipeline transportation congestion, drilling technologies, potential market speculation, and other factors that affect supply and demand. We also manage commodity price risk with physical gas reserves from a long-term investment in working interests in gas leases operated by Jonah Energy. These financial hedge contracts and gas reserves volumes are generally included in our annual PGA filing for recovery, subject to a regulatory prudence review.

Interest Rate Risk

We are exposed to interest rate risk primarily associated with new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. Interest rate risk is primarily managed through the issuance of fixed-rate debt with varying maturities. We may also enter into financial derivative instruments, including interest rate swaps, options and other hedging instruments, to manage and mitigate interest rate exposure.

Foreign Currency Risk

The costs of certain natural gas commodity supplies and certain pipeline and off-system storage 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 for our commodity and commodity-related demand and reservation charges paid in Canadian dollars. If all of the foreign currency forward contracts had been settled on December 31, 2014, a loss of $0.4 million would have been realized. See Note 13.

Credit Risk

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

CREDIT EXPOSURE TO FINANCIAL DERIVATIVE COUNTERPARTIES. Based on estimated fair value at December 31, 2014, our overall credit exposure relating to commodity contracts is considered immaterial as it reflects

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amounts owed to financial derivative counterparties (see table below). However, changes in natural gas prices could result in counterparties owing us money. Therefore, our financial derivatives policy requires counterparties to have at least an investment-grade credit rating at the time the derivative instrument is entered into and specific limits on the contract amount and duration based on each counterparty's credit rating. Due to potential changes in market conditions and credit concerns, we continue to enforce strong credit requirements. We actively monitor and manage our derivative credit exposure and place counterparties on hold for trading purposes or require cash collateral, letters of credit, or guarantees as circumstances warrant. As of December 31, 2014, we do not have any actual derivative credit risk exposure for amounts financial derivative counterparties owe to us.

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

	Financial Derivative Position by Credit Rating		
	Unrealized Fair Value Gain (Loss)		
In millions	2014		2013
AAA/Aaa	$—		$—
AA/Aa	(27.2	)	4.5
A/A	(3.4	)	0.9
BBB/Baa	—		—
Total	$(30.6	)	$5.4

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

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

CREDIT EXPOSURE TO INSURANCE COMPANIES.
Our credit exposure to insurance companies for loss or damage claims could be material. We regularly monitor the financial condition of insurance companies who provide general liability insurance policy coverage to NW Natural and its predecessors.

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. We have a weather normalization mechanism in Oregon for residential and commercial customers, which 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, 2014, approximately 7% of our Oregon customers had opted out. In addition to the Oregon customers opting out, our

Washington residential and commercial customers account for approximately 11% 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% of all residential and commercial customers. See "Results of Operations—Regulatory Matters—Rate Mechanism—Weather Normalization Tariff" above.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Supplemental Schedules Omitted

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

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MANAGEMENT’S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

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

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

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2014. 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 (2013).

Based on our assessment and those criteria, management has concluded that we maintained effective internal control over financial reporting as of December 31, 2014.

The effectiveness of internal control over financial reporting as of December 31, 2014 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in this annual report.

/s/ Gregg S. Kantor
Gregg S. Kantor
President and Chief Executive Officer

/s/ Stephen P. Feltz
Stephen P. Feltz
Senior Vice President and Chief Financial Officer

February 27, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying table of contents present fairly, in all material respects, the financial position of Northwest Natural Gas Company and its subsidiaries at December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 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, 2014, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

Portland, Oregon
February 27, 2015

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

In thousands, except per share data	Year Ended December 31, 2014	2013	2012
Operating revenues	$754,037	$758,518	$730,607
Operating expenses:			
Cost of gas	365,490	373,298	355,335
Operations and maintenance	136,982	136,613	129,477
General taxes	29,407	29,956	30,598
Depreciation and amortization	79,193	75,905	73,017
Total operating expenses	611,072	615,772	588,427
Income from operations	142,965	142,746	142,180
Other income and expense, net	1,933	4,669	3,159
Interest expense, net	44,563	45,172	43,157
Income before income taxes	100,335	102,243	102,182
Income tax expense	41,643	41,705	43,403
Net income	58,692	60,538	58,779
Other comprehensive income:			
Change in employee benefit plan liability, net of taxes of $2,857 for 2014, ($1,304) for 2013, and $1,339 for 2012	(4,364)	1,998	(2,156)
Amortization of non-qualified employee benefit plan liability, net of taxes of ($438) for 2014, ($608) for 2013, and ($434) for 2012	646	935	665
Comprehensive income	$54,974	$63,471	$57,288
Average common shares outstanding:			
Basic	27,164	26,974	26,831
Diluted	27,223	27,027	26,907
Earnings per share of common stock:			
Basic	$2.16	$2.24	$2.19
Diluted	2.16	2.24	2.18
Dividends declared per share of common stock	1.85	1.83	1.79

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
In thousands	2014	2013
Assets:		
Current assets:		
Cash and cash equivalents	$9,534	$9,471
Accounts receivable	69,818	81,889
Accrued unbilled revenue	57,963	61,527
Allowance for uncollectible accounts	(969)	(1,656)
Regulatory assets	68,562	22,635
Derivative instruments	243	5,311
Inventories	77,832	60,669
Gas reserves	20,020	20,646
Income taxes receivable	1,000	3,534
Deferred tax assets	23,785	45,241
Other current assets	34,772	21,181
Total current assets	362,560	330,448
Non-current assets:		
Property, plant, and equipment	2,992,560	2,918,739
Less: Accumulated depreciation	870,967	855,865
Total property, plant, and equipment, net	2,121,593	2,062,874
Gas reserves	129,280	121,998
Regulatory assets	368,908	369,603
Derivative instruments	—	1,880
Other investments	68,238	67,851
Restricted cash	3,000	4,000
Other non-current assets	11,366	12,257
Total non-current assets	2,702,385	2,640,463
Total assets	$3,064,945	$2,970,911

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

In thousands	As of December 31, 2014	2013
Liabilities and equity:		
Current liabilities:		
Short-term debt	$234,700	$188,200
Current maturities of long-term debt	40,000	60,000
Accounts payable	91,366	96,126
Taxes accrued	10,031	10,856
Interest accrued	6,079	7,103
Regulatory liabilities	19,105	28,335
Derivative instruments	29,894	1,891
Other current liabilities	38,235	40,280
Total current liabilities	469,410	432,791
Long-term debt	621,700	681,700
Deferred credits and other non-current liabilities:		
Deferred tax liabilities	530,965	532,036
Regulatory liabilities	317,205	303,485
Pension and other postretirement benefit liabilities	236,735	149,354
Derivative instruments	3,515	615
Other non-current liabilities	118,094	119,058
Total deferred credits and other non-current liabilities	1,206,514	1,104,548
Commitments and contingencies (see Note 14 and Note 15)	—	—
Equity:		
Common stock - no par value; authorized 100,000 shares; issued and outstanding 27,284 and 27,075 at December 31, 2014 and 2013, respectively	375,117	364,549
Retained earnings	402,280	393,681
Accumulated other comprehensive loss	(10,076)	(6,358)
Total equity	767,321	751,872
Total liabilities and equity	$3,064,945	$2,970,911

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

In thousands	Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Equity
Balance at December 31, 2011	$348,383	$371,575	$(7,800)	$712,158
Comprehensive income (loss)	—	58,779	(1,491)	57,288
Dividends paid on common stock	—	(48,007)	—	(48,007)
Tax expense from employee stock option plan	(149)	—	—	(149)
Stock-based compensation	1,291	—	—	1,291
Issuance of common stock	7,046	—	—	7,046
Balance at December 31, 2012	356,571	382,347	(9,291)	729,627
Comprehensive income	—	60,538	2,933	63,471
Dividends paid on common stock	—	(49,204)	—	(49,204)
Tax expense from employee stock option plan	(242)	—	—	(242)
Stock-based compensation	2,169	—	—	2,169
Issuance of common stock	6,051	—	—	6,051
Balance at December 31, 2013	364,549	393,681	(6,358)	751,872
Comprehensive income (loss)	—	58,692	(3,718)	54,974
Dividends paid on common stock	—	(50,093)	—	(50,093)
Tax expense from stock-based compensation plans	(117)	—	—	(117)
Stock-based compensation	1,646	—	—	1,646
Issuance of common stock	9,039	—	—	9,039
Balance at December 31, 2014	$375,117	$402,280	$(10,076)	$767,321

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
In thousands	2014	2013	2012
Operating activities:			
Net income	$58,692	$60,538	$58,779
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	79,193	75,905	73,017
Regulatory amortization of gas reserves	19,335	11,089	6,340
Deferred tax liabilities, net	24,772	46,483	42,079
Non-cash expenses related to qualified defined benefit pension plans	4,984	5,666	5,448
Contributions to qualified defined benefit pension plans	(10,500)	(11,700)	(23,500)
Deferred environmental recoveries, net of (expenditures)	88,849	(16,679)	(12,503)
Other	1,853	(2,580)	(2,350)
Changes in assets and liabilities:			
Receivables, net	14,948	(26,094)	22,170
Inventories	(17,163)	6,933	6,761
Taxes accrued	1,709	286	3,334
Accounts payable	(2,020)	7,422	(602)
Interest accrued	(1,024)	1,150	96
Deferred gas costs	(23,114)	(5,245)	(17,644)
Other, net	(24,857)	23,216	7,413
Cash provided by operating activities	215,657	176,390	168,838
Investing activities:			
Capital expenditures	(120,092)	(138,924)	(132,029)
Utility gas reserves	(26,798)	(54,077)	(54,085)
Proceeds from sale of assets	175	8,638	—
Restricted cash	1,000	—	—
Other	1,392	2,231	1,437
Cash used in investing activities	(144,323)	(182,132)	(184,677)
Financing activities:			
Common stock issued, net	8,986	5,964	6,758
Long-term debt issued	—	50,000	50,000
Long-term debt retired	(80,000)	—	(40,000)
Change in short-term debt	46,500	(2,050)	48,650
Cash dividend payments on common stock	(50,093)	(49,204)	(48,007)
Other	3,336	1,580	1,528
Cash (used in) provided by financing activities	(71,271)	6,290	18,929
Increase in cash and cash equivalents	63	548	3,090
Cash and cash equivalents, beginning of period	9,471	8,923	5,833
Cash and cash equivalents, end of period	$9,534	$9,471	$8,923
Supplemental disclosure of cash flow information:			
Interest paid	$42,602	$44,022	$43,061
Income taxes paid	19,445	870	2,979

See Notes to Consolidated Financial Statements

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NORTHWEST NATURAL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND PRINCIPLES OF CONSOLIDATION

The accompanying consolidated financial statements represent the consolidated results of Northwest Natural Gas Company (NW Natural or the Company) and all companies that we directly or indirectly control, either through majority ownership or otherwise. We have two core businesses: our regulated local gas distribution business, referred to as the utility segment, which serves residential, commercial, and industrial customers in Oregon and southwest Washington; and our gas storage businesses, referred to as the gas storage segment, which provides storage services for utilities, gas marketers, electric generators, and large industrial users from storage facilities located in Oregon and California. In addition, we have investments and other non-utility activities we aggregate and report as other.

Our core utility business assets and operating activities are largely included in the parent company, NW Natural. Our direct and indirect wholly-owned subsidiaries include NW Natural Energy, LLC (NWN Energy), NW Natural Gas Storage, LLC (NWN Gas Storage), Gill Ranch Storage, LLC (Gill Ranch), NNG Financial Corporation (NNG Financial), Northwest Energy Corporation (Energy Corp), and NW Natural Gas Reserves, LLC (NWN Gas Reserves). Investments in corporate joint ventures and partnerships we do not directly or indirectly control, and for which we are not the primary beneficiary, are accounted for under the equity method, which includes NWN Energy's investment in Trail West Pipeline, LLC (TWP) and NNG Financial's investment in Kelso-Beaver (KB) Pipeline. NW Natural and its affiliated companies are collectively referred to herein as NW Natural. The consolidated financial statements are presented after elimination of all intercompany balances and transactions, except for amounts required to be included under regulatory accounting standards to reflect the effect of such regulation. 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 businesses and other non-utility investments and business activities.

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

2. SIGNIFICANT ACCOUNTING POLICIES

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 most likely be reported in future periods. Management believes the estimates and assumptions used are reasonable.

Industry Regulation
Our principal businesses are the distribution of natural gas, which is regulated by the OPUC and WUTC, and natural gas storage services, which are regulated by either the FERC or the CPUC, and to a certain extent by the OPUC and WUTC. Accounting records and practices of our regulated businesses conform to the requirements and uniform system of accounts prescribed by these regulatory authorities in accordance with GAAP. Our businesses regulated by

the OPUC, WUTC, and FERC earn a reasonable return on invested capital from approved cost-based rates, while our business regulated by the CPUC earns a return to the extent we are able to charge competitive prices above our costs (i.e. market-based rates).

In applying regulatory accounting principles, we capitalize or defer certain costs and revenues as regulatory assets and liabilities pursuant to orders of the OPUC or WUTC, which provide for the recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge in certain cases.

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

	Regulatory Assets	
In thousands	2014	2013
Current:		
Unrealized loss on derivatives[(1)]	$29,889	$1,891
Gas costs	21,794	4,286
Other[(2)]	16,879	16,458
Total current	$68,562	$22,635
Non-current:		
Unrealized loss on derivatives[(1)]	$3,515	$615
Pension balancing[(3)]	32,541	25,713
Income taxes	47,427	51,814
Pension and other postretirement benefit liabilities[(3)]	201,845	125,855
Environmental costs[(4)]	58,859	148,389
Gas costs	5,971	1,840
Other[(2)]	18,750	15,377
Total non-current	$368,908	$369,603

	Regulatory Liabilities	
In thousands	2014	2013
Current:		
Gas costs	$5,700	$7,510
Unrealized gain on derivatives[(1)]	240	5,290
Other[(2)]	13,165	15,535
Total current	$19,105	$28,335
Non-current:		
Gas costs	$2,507	$2,172
Unrealized gain on derivatives[(1)]	—	1,880
Accrued asset removal costs[(5)]	311,238	296,294
Other[(2)]	3,460	3,139
Total non-current	$317,205	$303,485

(1) Unrealized gains or losses on derivatives are non-cash items and, therefore, do not earn a rate of return or a carrying charge. These amounts are recoverable through utility rates as part of the annual Purchased Gas Adjustment (PGA) mechanism when realized at settlement.

(2) These balances primarily consist of deferrals and amortizations under approved regulatory mechanisms. The accounts being amortized typically earn a rate of return or carrying charge.

(3) Certain utility pension costs are approved for regulatory deferral, including amounts recorded to the pension balancing account, to mitigate the effects of higher and lower pension expenses. Deferred pension costs include an interest component when recognized in net periodic benefit costs. See Note 8.

(4) Environmental costs relate to specific sites approved for regulatory deferral by the OPUC and WUTC. In Oregon, we earn a carrying charge on cash amounts paid, whereas amounts accrued but not yet paid do not earn a carrying charge until expended. We also accrue a carrying charge on insurance proceeds for amounts owed to customers. In Washington, a carrying charge related to deferred amounts will be determined in a future proceeding. See Note 15.

(5) Estimated costs of removal on certain regulated properties are collected through rates. See "Accounting Policies—Plant, Property, and Accrued Asset Removal Costs" below.

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

We believe all costs incurred and deferred at December 31, 2014 are prudent. We annually review all regulatory assets and liabilities for recoverability and more often if circumstances warrant. If we should determine that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of regulatory accounting, then we would be required to write off the net unrecoverable balances in the period such determination is made. See Note 16 for information regarding the resolution of the environmental Site Remediation and Recovery Mechanism (SRRM) in February 2015. In accordance with accounting guidance and the Company's policy, a $15 million pre-tax regulatory disallowance will be recognized in the first quarter of 2015 related to the Order.

New Accounting Standards

Recently Issued Accounting Pronouncements

REVENUE RECOGNITION. On May 28, 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2014-09 Revenue From Contracts with Customers. The underlying principle of the guidance requires entities to recognize revenue depicting the transfer of goods or services to customers at amounts expected to be entitled to in exchange for those goods or services. The model provides a five-step approach to revenue recognition: (1) identify the contract(s) with the customer; (2) identify the separate performance obligations in the contract(s); (3) determine the transaction price; (4) allocate the transaction price to separate performance obligations; and (5) recognize revenue when, or as, each performance obligation is satisfied. The new requirements are effective beginning January 1, 2017, and either a full retrospective or simplified transition adoption method is allowed; early adoption is not permitted. NW Natural is currently assessing the impact of this standard on its financial statements and disclosures.

Accounting Policies

Plant, Property, and Accrued Asset Removal Costs

Plant and property are stated at cost, including capitalized labor, materials and overhead. In accordance with regulatory accounting standards, the cost of acquiring and constructing long-lived plant and property generally includes an allowance for funds used during construction (AFUDC) or capitalized interest. AFUDC represents the regulatory financing cost incurred when debt and equity funds are used for construction (see “AFUDC” below). When constructed assets are subject to market-based rates rather than cost-based rates, the financing costs incurred during construction are included in capitalized interest in accordance with GAAP, not as regulatory financing costs under AFUDC.

In accordance with long-standing regulatory treatment, our depreciation rates consist of three components: one based on the average service life of the asset, a second based on the estimated salvage value of the asset, and a third based on the asset's estimated cost of removal. We collect, through rates, the estimated cost of removal on certain regulated properties through depreciation expense, with a corresponding offset to accumulated depreciation. These removal costs are non-legal obligations as defined by regulatory accounting guidance. Therefore, we have included these costs as non-current regulatory liabilities rather than as accumulated depreciation on our consolidated balance sheets. In the rate setting process, the liability for removal costs is treated as a reduction to the net rate base on which the regulated utility has the opportunity to earn its allowed rate of return.

The costs of utility plant retired or otherwise disposed of are removed from utility plant and charged to accumulated depreciation for recovery or refund through future rates. Gains from the sale of regulated assets are generally deferred and refunded to customers. For non-utility assets, we record a gain or loss upon the disposal of the property. The gain or loss is recorded in other income and expense, net in the consolidated statements of comprehensive income.

Our provision for depreciation of utility property, plant, and equipment is recorded under the group method on a straight-line basis with rates computed in accordance with depreciation studies approved by regulatory authorities. The weighted-average depreciation rate for utility assets in service was approximately 2.8% for 2014, 2013, and 2012, reflecting the approximate weighted-average economic life of the property. This includes 2014 weighted-average depreciation rates for the following asset categories: 2.7% for transmission and distribution plant, 2.2% for gas storage facilities, 4.7% for general plant, and 2.9% for intangible and other fixed assets.

AFUDC. Certain additions to utility plant include AFUDC, which represents the net cost of debt and equity funds used during construction. AFUDC is calculated using actual interest rates for debt and authorized rates for ROE, if applicable. If short-term debt balances are less than the total balance of construction work in progress, then a composite AFUDC rate is used to represent interest on all debt funds, shown as a reduction to interest charges, and on ROE funds, shown as other income. While cash is not immediately recognized from recording AFUDC, it is realized in future years through rate recovery resulting from the higher utility cost of service. Our composite AFUDC rate was 0.3% in 2014, 2013, and 2012.

IMPAIRMENT OF LONG-LIVED ASSETS. We review the carrying value of long-lived assets whenever events or changes in circumstances indicate that the carrying amount of the assets might not be recoverable. Factors that would necessitate an impairment assessment of long-lived assets include a significant adverse change in the extent or manner in which the asset is used, a significant adverse change in

legal factors or business climate that could affect the value of the asset, or a significant decline in the observable market value or expected future cash flows of the asset, among others.

If such factors indicate a potential impairment, we assess the recoverability by determining if the carrying value of the asset exceeds the sum of the projected future cash flows over the remaining economic life of the asset. An asset is determined to be impaired when the carrying value is not recoverable through undiscounted future cash flows, and in those cases, we would estimate the fair value of the asset using appropriate valuation methodologies, which may include an estimate of discounted cash flows. Any impairment would be measured as the difference between the asset's carrying amount and its estimated fair value.

We have determined there were no events or circumstances that suggested an impairment of long-lived assets during the year ended December 31, 2014. In reaching this conclusion, we reviewed all long-lived assets for circumstances, including those noted above, that may indicate the carrying amount of the asset might not be recoverable and determined no such events have occurred. If our gas storage facilities experience sustained decreases in future cash flows due to a prolonged, slow recovery of the gas storage market, this may lead to events that indicate the carrying amount of the assets might not be recoverable, requiring an impairment assessment that could result in a future impairment.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand plus highly liquid investment accounts with original maturity dates of three months or less. At December 31, 2014 and 2013, outstanding checks of approximately $5.5 million and $2.8 million, respectively, were included in accounts payable.

Revenue Recognition and Accrued Unbilled Revenue

Utility revenues, derived primarily from the sale and transportation of natural gas, are recognized upon delivery of the gas commodity or service to customers. Revenues include accruals for gas delivered but not yet billed to customers based on estimates of deliveries from meter reading dates to month end (accrued unbilled revenue). Accrued unbilled revenue is dependent upon a number of factors that require management’s judgment, including total gas receipts and deliveries, customer use by billing cycle, and weather factors. Accrued unbilled revenue is reversed the following month when actual billings occur. Our accrued unbilled revenue at December 31, 2014 and 2013 was $58.0 million and $61.5 million, respectively.

Non-utility revenues are derived primarily from the gas storage segment. At our Mist underground storage facility, revenues are primarily firm service revenues in the form of fixed monthly reservation charges. At our Gill Ranch facility, firm storage services resulting from short-term and long-term contracts are typically recognized in revenue ratably over the term of the contract regardless of the actual storage capacity utilized. In addition, we also have asset management service revenue primarily from an independent energy marketing company that optimizes commodity and pipeline capacity release transactions. Under this agreement, guaranteed asset management revenue is recognized using a straight-line, pro-rata methodology over the term of each contract. Revenues earned above the guaranteed amount are recognized as they are earned. See Note 4.

Revenue Taxes

Revenue-based taxes are primarily franchise taxes, which are collected from customers and remitted to taxing authorities. Revenue taxes are included in operating revenues in the statement of comprehensive income. Revenue taxes were $18.8 million, $19.0 million, and $18.4 million for 2014, 2013, and 2012, respectively.

Accounts Receivable and Allowance for Uncollectible Accounts

Accounts receivable consist primarily of amounts due for natural gas sales and transportation services to utility customers, plus amounts due for gas storage services. With respect to these trade receivables, including accrued unbilled revenue, we establish an allowance for uncollectible accounts (allowance) based on the aging of receivables, collection experience of past due account balances including payment plans, and historical trends of write-offs as a percent of revenues. With respect to large individual customer receivables, a specific allowance is established and recorded 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 uncollectible. Differences between our estimated allowance and actual write-offs will occur based on a number of factors, including changes in economic conditions, customer creditworthiness, and natural gas prices. Each quarter the allowance for uncollectible accounts is adjusted, as necessary, based on information currently available.

Inventories

Utility gas inventories, which consist of natural gas in storage for the utility, are stated at the lower of average cost or net realizable value. The regulatory treatment of utility gas inventories provides for cost recovery in customer rates. Utility gas inventories injected into storage are priced in inventory based on actual purchase costs. Utility gas inventories withdrawn from storage are charged to cost of gas during the current period at the weighted-average inventory cost.

Gas storage inventories, which primarily represent inventories at the Gill Ranch storage facility, mainly consist of natural gas received as fuel-in-kind from storage customers. Gas storage inventories are valued at the lower of average cost or net realizable value. Cushion gas is not included in our inventory balances and is recorded at original cost and classified as a long-term plant asset.

Materials and supplies inventories consist of both utility and non-utility inventories and are stated at the lower of average cost or net realizable value.

Our utility and gas storage inventories totaled $68.0 million and $51.4 million at December 31, 2014 and 2013, respectively. At December 31, 2014 and 2013, our materials

and supplies inventories totaled $9.8 million and $9.3 million, respectively.

Gas Reserves

Our gas reserves are stated at cost, adjusted for regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet. Transactional costs to enter into the agreements and payments by NW Natural to acquire gas reserves are recognized as gas reserves on the balance sheet. The current portion is calculated based on expected gas deliveries within the next fiscal year. We recognize regulatory amortization of this asset on a volumetric basis calculated using the estimated gas reserves and the estimated therms extracted and sold each month. The amortization of gas reserves is recorded to cost of gas along with gas production revenues and production costs. See Note 11.

Derivatives

In accordance with accounting for derivatives and hedges, we measure derivatives at fair value and recognize them as either assets or liabilities on the balance sheet. Accounting for derivatives requires that changes in the fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for derivatives and hedges provides an exception for contracts intended for normal purchases and normal sales for which physical delivery is probable. In addition, certain derivative contracts are approved by regulatory authorities for recovery or refund through customer rates. Accordingly, the changes in fair value of these approved contracts are deferred as regulatory assets or liabilities pursuant to regulatory accounting principles. Our financial derivatives generally qualify for deferral under regulatory accounting. The Company's index-priced physical derivative contracts also qualify for regulatory deferral accounting treatment.

Derivative contracts entered into for utility requirements after the annual PGA rate has been set and during the PGA year are subject to the PGA incentive sharing mechanism. In Oregon we participate in a PGA sharing mechanism under which we are required to select either an 80% or 90% deferral of higher or lower gas costs such that the impact on current earnings from the gas cost sharing is either 20% or 10% of gas cost differences compared to PGA prices, respectively. For the PGA years in Oregon beginning November 1, 2014, 2013, and 2012, we selected a 90% deferral of gas cost differences. In Washington, 100% of the differences between the PGA prices and actual gas costs are deferred. See Note 13.

Our financial derivatives policy sets forth the guidelines for using selected derivative products to support prudent risk management strategies within designated parameters. Our objective for using derivatives is to decrease the volatility of gas prices, earnings, and cash flows without 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 determined necessary to support normal business activities. We do not enter into derivative instruments for trading purposes.

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Fair Value

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

- Level 1: Valuation is based on quoted prices for identical instruments traded in active markets;
- Level 2: Valuation is based on quoted prices for similar instruments in active markets, quoted prices for identical or similar instruments in markets that are not active, and model-based valuation techniques for which all significant assumptions are observable in the market; and
- Level 3: Valuation is generated from model-based techniques that use significant assumptions not observable in the market. These unobservable assumptions reflect our own estimates of assumptions market participants would use in valuing the asset or liability.

When developing fair value measurements, it is our policy to use quoted market prices whenever available, or to maximize the use of observable inputs and minimize the use of unobservable inputs when quoted market prices are not available. Fair values are primarily developed using industry-standard models that consider various inputs including: (a) quoted future prices for commodities; (b) forward currency prices; (c) time value; (d) volatility factors; (e) current market and contractual prices for underlying instruments; (f) market interest rates and yield curves; (g) credit spreads; and (h) other relevant economic measures.

Income Taxes

We account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined on the basis of the differences 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. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date unless a regulatory order specifies deferral of the effect of the change in tax rates over a longer period of time.

Deferred income tax assets and liabilities are also recognized for temporary differences where the deferred income tax benefits or expenses have previously been flowed through in the ratemaking process of the regulated utility. Regulatory tax assets and liabilities are recorded on these deferred tax assets and liabilities to the extent the Company believes they will be recoverable from or refunded to customers in future rates. At December 31, 2014 and 2013, regulatory income tax assets of $51.8 million and

$56.2 million, respectively, were recorded, a portion of which is recorded in current assets. These regulatory income tax assets primarily represent future rate recovery of deferred tax liabilities, resulting from differences in utility plant financial statement and tax bases and utility plant removal costs, which were previously flowed through for rate making purposes and to take into account the additional future taxes, which will be generated by that recovery. These deferred tax liabilities, and the associated regulatory income tax assets, are currently being recovered through customer rates.

Deferred investment tax credits on utility plant additions, which reduce income taxes payable, are deferred for financial statement purposes and amortized over the life of the related plant.

The Company recognizes interest and penalties related to unrecognized tax benefits, if any, within income tax expense and accrued interest and penalties within the related tax liability line in the consolidated balance sheets. No accrued interest or penalties for uncertain tax benefits have been recorded. See Note 9.

Environmental Contingencies

Loss contingencies are recorded as liabilities when it is probable a liability has been incurred and the amount of the loss is reasonably estimable in accordance with accounting standards for contingencies. 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.

With respect to environmental liabilities and related costs, we develop estimates based on a review of information available from numerous sources, including completed studies and site specific negotiations. 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, it is our policy to accrue at the low end of the range. Accordingly, due to numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases we have disclosed the nature of the potential loss and the fact that the high end of the range cannot be reasonably estimated. See Note 15.

Subsequent Events
See Note 16 for information regarding the resolution of the environmental SRRM docket.

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3. EARNINGS PER SHARE

Basic earnings per share are computed using net income and the weighted average number of common shares outstanding for each period presented. Diluted earnings per share are computed in the same manner, except it uses the weighted average number of common shares outstanding plus the effects of the assumed exercise of stock options and the payment of estimated stock awards from other stock-based compensation plans that are outstanding at the end of each period presented. Diluted earnings per share are calculated as follows:

In thousands, except per share data	2014	2013	2012
Net income	$58,692	$60,538	$58,779
Average common shares outstanding - basic	27,164	26,974	26,831
Additional shares for stock-based compensation plans (See Note 6)	59	53	76
Average common shares outstanding - diluted	27,223	27,027	26,907
Earnings per share of common stock - basic	$2.16	$2.24	$2.19
Earnings per share of common stock - diluted	$2.16	$2.24	$2.18
Additional information:			
Antidilutive shares not included in net income per diluted common share calculation	18	26	1

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4. SEGMENT INFORMATION

We primarily operate in two primary reportable business segments, local gas distribution and gas storage. We also have other investments and business activities not specifically related to one of these two reporting segments, which we aggregate and report as other. We refer to our local gas distribution business as the utility, and our gas storage segment and other as non-utility. Our utility segment also includes NWN Gas Reserves, which is a wholly-owned subsidiary of Energy Corp and the utility portion of Mist. Our gas storage segment includes NWN Gas Storage, which is a wholly-owned subsidiary of NWN Energy, Gill Ranch, which is a wholly-owned subsidiary of NWN Gas Storage, the non-utility portion of Mist, and all third-party asset management services. Other includes NNG Financial and NWN Energy's equity investment in TWH, which is pursuing development of a cross-Cascades transmission pipeline project. See Other, below.

Local Gas Distribution

Our local gas distribution segment is a regulated utility principally engaged in the purchase, sale, and delivery of natural gas and related services to customers in Oregon and southwest Washington. As a regulated utility, we are responsible for building and maintaining a safe and reliable pipeline distribution system, purchasing sufficient gas supplies from producers and marketers, contracting for firm and interruptible transportation of gas over interstate pipelines to bring gas from the supply basins into our service territory, and re-selling the gas to customers subject to rates, terms, and conditions approved by the OPUC or WUTC. Gas distribution also includes taking customer-owned gas and transporting it from interstate pipeline connections, or city gates, to the customers’ end-use facilities for a fee, which is approved by the OPUC or WUTC. Approximately 89% of our customers are located in Oregon and 11% in Washington. On an annual basis, residential and commercial customers typically account for around 60% of our utility’s total volumes delivered and 90% of our utility’s margin. Industrial customers largely account for the remaining volumes and utility margin. A small amount of utility margin is also derived from miscellaneous services, gains or losses from an incentive gas cost sharing mechanism, and other service fees.

Industrial sectors we serve include: pulp, paper, and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery and textiles; the manufacture of asphalt, concrete and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation. No individual customer or industry group accounts for over 10% of our utility revenues or utility margins.

Gas Storage

Our gas storage segment includes natural gas storage services provided to customers primarily from two underground natural gas storage facilities, our Gill Ranch gas storage facility, and the non-utility portion of our Mist gas storage facility. In addition to earning revenue from customer storage contracts, we also use an independent energy marketing company to provide asset management services for utility and non-utility capacity, the results of which are included in this business segment. For the years ended December 31, 2014, 2013, and 2012, this business segment derived a majority of its revenues from firm and interruptible gas storage contracts and from asset management services.

Mist Gas Storage Facility

Earnings from non-utility assets at our Mist facility in Oregon are primarily related to firm storage capacity revenues. Earnings for the Mist facility also includes revenue, net of amounts shared with utility customers, from management of utility assets at Mist and upstream capacity when not needed to serve utility customers. We retain 80% of the pre-tax income from these services when the costs of the capacity have not been included in utility rates, or 33% of the pre-tax income when the costs have been included in utility rates. The remaining 20% and 67%, respectively, are recorded to a deferred regulatory account for crediting back to utility customers.

Gill Ranch Gas Storage Facility
Gill Ranch has a joint project agreement with Pacific Gas and Electric Company (PG&E) to own and operate the Gill Ranch underground natural gas storage facility near Fresno, California. Gill Ranch has a 75% undivided ownership interest in the facility and is also the operator of the facility, which offers storage services to the California market at market-based rates, subject to CPUC regulation including, but not limited to, service terms and conditions and tariff regulations. Although this is a jointly owned property, each owner is independently responsible for financing its share of the Gill Ranch natural gas storage facility. Revenues are primarily related to firm storage capacity as well as asset management revenues.

Other
We have non-utility investments and other business activities, which are aggregated and reported as other. Other primarily consists of an equity method investment in Trail West Holdings (TWH), which was formed to build and operate an interstate gas transmission pipeline in Oregon (TWP) and other pipeline assets in NNG Financial. For more information on TWP, see Note 12. Other also includes some operating and non-operating revenues and expenses of the parent company that cannot be allocated to utility operations.

NNG Financial holds certain non-utility financial investments, but its assets primarily consist of an active, wholly-owned subsidiary which owns a 10% interest in an 18-mile interstate natural gas pipeline. NNG Financial's total assets were $0.8 million and $1.2 million at December 31, 2014 and 2013, respectively.

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Segment Information Summary

Inter-segment transactions are insignificant. The following table presents summary financial information concerning the reportable segments:

In thousands	Utility	Gas Storage	Other	Total
2014				
Operating revenues	$731,578	$22,235	$224	$754,037
Depreciation and amortization	72,660	6,533	—	79,193
Income from operations	138,711	3,987	267	142,965
Net income	58,587	(364)	469	58,692
Capital expenditures	117,322	2,770	—	120,092
Total assets at December 31, 2014	2,775,011	273,813	16,121	3,064,945
2013				
Operating revenues	$727,182	$31,112	$224	$758,518
Depreciation and amortization	69,420	6,485	—	75,905
Income from operations	128,066	14,669	11	142,746
Net income	54,920	5,569	49	60,538
Capital expenditures	137,466	1,458	—	138,924
Total assets at December 31, 2013	2,644,367	310,097	16,447	2,970,911
2012				
Operating revenues	$699,862	$30,520	$225	$730,607
Depreciation and amortization	66,545	6,472	—	73,017
Income from operations	128,854	13,226	100	142,180
Net income	54,049	4,521	209	58,779
Capital expenditures	130,151	1,541	337	132,029
Total assets at December 31, 2012	2,505,655	291,568	15,897	2,813,120

Utility Margin

Utility margin is a financial measure consisting of utility operating revenues, which are reduced by revenue taxes and the associated cost of gas. The cost of gas purchased for utility customers is generally a pass-through cost in the amount of revenues billed to regulated utility customers. By subtracting costs of gas from utility operating revenues, utility margin provides a key metric used by our chief operating decision maker in assessing the performance of the utility segment. The gas storage and other segments emphasize growth in operating revenues and net income as opposed to margin because these segments do not incur a product cost (i.e. cost of gas sold) like the utility and, therefore, use operating revenues and net income to assess performance.

The following table presents additional segment information concerning utility margin:

In thousands	2014	2013	2012
Utility margin calculation:			
Utility operating revenues	$731,578	$727,182	$699,862
Less: Utility cost of gas	365,490	373,298	355,335
Utility margin	$366,088	$353,884	$344,527

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5. COMMON STOCK

Common Stock

As of December 31, 2014 and 2013, we had 100 million shares of common stock authorized. As of December 31, 2014, we had reserved 97,921 shares for issuance of common stock under the Employee Stock Purchase Plan (ESPP) and 394,903 shares under our Dividend Reinvestment and Direct Stock Purchase Plan (DRPP). The Restated Stock Option Plan (SOP) was terminated with respect to new grants in 2012; however, options granted before the Restated SOP was terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. There were 416,088 options outstanding at December 31, 2014, which were granted prior to termination of the plan.

Stock Repurchase Program

We have a share repurchase program under which we may purchase our common shares on the open market or through privately negotiated transactions. We currently have Board authorization through May 2015 to repurchase up to an aggregate of 2.8 million shares, but not to exceed $100 million. No shares of common stock were repurchased pursuant to this program during the year ended December 31, 2014. Since the plan’s inception in 2000 a total of 2.1 million shares have been repurchased at a total cost of $83.3 million.

Summary of Changes in Common Stock

The following table shows the changes in the number of shares of our common stock issued and outstanding:

In thousands	Shares
Balance, December 31, 2011	26,756
Sales to employees under ESPP	18
Stock-based compensation	47
Sales to shareholders under DRPP	96
Balance, December 31, 2012	26,917
Sales to employees under ESPP	16
Stock-based compensation	42
Sales to shareholders under DRPP	100
Balance, December 31, 2013	27,075
Sales to employees under ESPP	24
Stock-based compensation	83
Sales to shareholders under DRPP	102
Balance, December 31, 2014	27,284

6. STOCK-BASED COMPENSATION

Our stock-based compensation plans are designed to promote stock ownership in NW Natural by employees and officers. These compensation plans include a Long-Term Incentive Plan (LTIP), an ESPP, and a Restated SOP. A variety of equity programs may be granted under the

LTIP. The Restated SOP was terminated in 2012 with respect to new grants; however, options granted before the Restated SOP was terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. Any new grants of stock options would be made under the LTIP. No stock options were granted under the LTIP during the year ended December 31, 2014.

Long-Term Incentive Plan

The LTIP is intended to provide a flexible, competitive compensation program for eligible officers and key employees. Under the LTIP, shares of common stock are authorized for equity incentive grants in the form of stock, restricted stock, restricted stock units, stock options, or performance shares. An aggregate of 850,000 shares were authorized for issuance as of December 31, 2014. Shares awarded under the LTIP may be purchased on the open market or issued as original shares.

Of the 850,000 shares of common stock authorized for LTIP awards at December 31, 2014, there were 225,669 shares available for issuance under any type of award and 250,000 shares available for option grants. This assumes that market, performance, and service based grants currently outstanding are awarded at the target level. There were no outstanding grants of restricted stock or stock options under the LTIP at December 31, 2014 or 2013. The LTIP stock awards are compensatory awards for which compensation expense is based on the fair value of stock awards, with expense being recognized over the performance and vesting period of the outstanding awards.

Performance Shares

Since the LTIP's inception in 2001, performance shares, which incorporate market, performance, and service-based factors, have been granted annually with three-year performance periods. The following table summarizes performance share expense information:

Dollars in millions	Shares[(1)]	Expense During Award Year[(3)]	Total Expense for Award
Estimated award:			
2012-2014 grant[(2)]	8,408	$0.6	$1.8
Actual award:			
2011-2013 grant	9,819	0.4	1.0
2010-2012 grant	9,924	0.5	1.2

(1) In addition to common stock shares, a participant also receives 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.

(2) This represents the estimated number of shares to be awarded as of December 31, 2014 as certain performance share measures had been achieved. Amounts are subject to change with final payout amounts authorized by the Board of Directors in February 2015.

(3) Amount represents the expense recognized in the third year of the vesting period noted above.

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The aggregate number of performance shares granted and outstanding at the target and maximum levels were as follows:

Dollars in thousands	Performance Share Awards Outstanding		2014	Cumulative Expense
Performance Period	Target	Maximum	Expense	December 31, 2014
2012-14	35,340	70,680	$583	$1,821
2013-15	37,300	74,600	442	928
2014-16	43,625	87,250	618	618
Total	116,265	232,530	$1,643	

For the 2012-2014 and 2013-2015 performance periods, awards will be based on total shareholder return (TSR factor) 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 (strategic factor). In addition to the TSR and strategic factors, the 2014-2016 award also included weighting for EPS and Return on Invested Capital (ROIC) factors. Compensation expense is recognized in accordance with the accounting standard for stock-based compensation and calculated based on performance levels achieved and an estimated fair value using the Monte-Carlo method. The weighted-average grant date fair value of unvested shares at December 31, 2014 and 2013 was $42.06 and $43.39 per share, respectively. The weighted-average grant date fair value of shares vested during the year was $43.67 per share and for shares granted during the year was $42.43 per share. As of December 31, 2014, there was $1.7 million of unrecognized compensation expense related to the unvested portion of performance awards expected to be recognized through 2016.

Restricted Stock Units

In 2012, the Company began granting RSUs under the LTIP instead of stock options under the Restated SOP. The fair value of an RSU is equal to the closing market price of the Company's common stock on the grant date. During 2014, total RSU expense was $0.9 million compared to $0.6 million in 2013. As of December 31, 2014, there was $2.2 million of unrecognized compensation cost from grants of RSUs, which is expected to be recognized over a period extending through 2019. Generally, RSUs awarded include a performance-based threshold and a vesting period of four years from the grant date. An RSU obligates the Company upon vesting to issue the RSU holder one share of common stock plus a cash payment equal to the total amount of dividends paid per share between the grant date and vesting date of that portion of the RSU.

Information regarding the RSU activity is summarized as follows:

	Number of RSUs		Weighted - Average Price Per RSU
Nonvested, December 31, 2011	—		$—
Granted	25,224		47.58
Vested	—		—
Forfeited	(360	)	48.00
Nonvested, December 31, 2012	24,864		$47.57
Granted	25,748		45.38
Vested	(5,455	)	48.01
Forfeited	(590	)	46.58
Nonvested, December 31, 2013	44,567		46.27
Granted	38,765		42.19
Vested	(12,060	)	46.52
Forfeited	(478	)	45.47

Nonvested, December 31, 2014	70,794	44.00

Restated Stock Option Plan

The Restated SOP was terminated for new option grants in 2012; however, options granted before the plan terminated will remain outstanding until the earlier of their expiration, forfeiture, or exercise. Any new grants of stock options would be made under the LTIP.

At December 31, 2014, a total of 416,088 shares of common stock remained reserved for issuance under the Restated SOP. As the plan is closed, there are no additional shares available for grant. Options under the Restated SOP were granted to officers and key employees designated by a committee of our Board of Directors. All options were granted at an option price equal to the closing market price on the date of grant and may be exercised for a period up to 10 years and seven days from the date of grant. Option holders may exchange shares they have owned for at least six months, valued at the current market price, to purchase shares at the option price.

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Information regarding the Restated SOP activity is summarized as follows:

	Option Shares	Weighted - Average Price Per Share	Intrinsic Value (In millions)
Balance outstanding, December 31, 2011	579,225	$42.09	$3.4
Exercised	(46,825)	40.62	0.4
Forfeited	(2,475)	43.78	n/a
Balance outstanding, December 31, 2012	529,925	42.22	1.3
Exercised	(33,800)	32.16	0.3
Forfeited	(3,975)	43.72	n/a
Balance outstanding, December 31, 2013	492,150	42.89	0.6
Exercised	(69,662)	39.82	0.5
Forfeited	(6,400)	43.59	n/a
Balance outstanding, December 31, 2014	416,088	43.40	2.7
Exercisable, December 31, 2014	388,965	43.23	2.6

During 2014, cash of $2.8 million was received for option shares exercised and $0.1 million related tax benefit was realized. During 2014, 2013, and 2012, the total fair value of options that vested was $0.4 million, $0.5 million and $0.6 million, respectively. The weighted average remaining life of options exercisable and outstanding at December 31, 2014 was 4.2 years and 4.3 years, respectively.

Employee Stock Purchase Plan

The ESPP allows employees to purchase common stock at 85% 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 $21,239 worth of stock through payroll deductions over a 12-month period, with shares issued at the end of the 12-month subscription period.

Stock-Based Compensation Expense

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

In thousands	2014	2013	2012
Operations and maintenance expense, for stock-based compensation	$2,309	$1,876	$1,668
Income tax benefit	(861)	(765)	(707)
Net stock-based compensation effect on net income	$1,448	$1,111	$961
Amounts capitalized for stock-based compensation	$597	$331	$294

7. DEBT

Short-Term Debt

Our primary source of short-term funds is from the sale of commercial paper and bank loans. In addition to issuing commercial paper or bank loans to meet seasonal working capital requirements, short-term debt is used temporarily to fund capital requirements. Commercial paper and bank loans are periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by one or more committed credit facilities. At December 31, 2014 and 2013, the amounts of commercial paper debt outstanding were $234.7 million and $188.2 million, respectively, and the average interest rate at December 31, 2014 and 2013 was 0.4% and 0.3%, respectively. The carrying cost of our commercial paper approximates fair value using Level 2 inputs, due to the short-term nature of the notes. See Note 2 for a description of the fair value hierarchy. At December 31, 2014, our commercial paper had a maximum maturity of 209 days and an average maturity of 98 days.

On December 20, 2012, NW Natural entered into a five-year $300 million credit agreement, with a feature that allows the Company to request increases in the total commitment amount up to a maximum amount of $450 million. The credit agreement also permitted NW Natural to extend commitments for two additional one-year periods, subject to lender approval. The Company exercised the first of these extensions in December 2013, and the second in December 2014 with a final maturity date of December 20, 2019. Also in December 2014, NW Natural amended the credit agreement to reduce the permitted letter of credit from $200 million to $100 million. Any principal and unpaid interest owed on borrowings under the agreement is due and payable on or before the expiration date. There were no outstanding balances under the agreement and no letters of credit issued or outstanding at December 31, 2014 and 2013.

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 or senior secured debt ratings, as applicable, 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 agreement also requires us to maintain a consolidated indebtedness to total capitalization ratio of 70% 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, 2014 and 2013.

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Long-Term Debt

The issuance of first mortgage bonds (FMBs), which includes our medium-term notes, under the Mortgage and Deed of Trust (Mortgage) is limited by eligible property, adjusted net earnings and other provisions of the Mortgage. The Mortgage constitutes a first mortgage lien on substantially all of our utility property. In addition, our Gill Ranch subsidiary senior secured debt is secured by all of the membership interests in Gill Ranch as well as Gill Ranch's debt service reserve account, which is recorded as restricted cash on the balance sheet.

Maturities and Outstanding Long-Term Debt

Retirement of long-term debt for each of the 12-month periods through December 31, 2019 and thereafter are as follows:

In thousands	
Year	
2015	$40,000
2016	45,000
2017	40,000
2018	22,000
2019	30,000
Thereafter	484,700

The following table presents our debt outstanding as of December 31:

In thousands	2014	2013
First Mortgage Bonds		
8.26 % Series B due 2014	$—	$10,000
3.95 % Series B due 2014	—	50,000
4.70 % Series B due 2015	40,000	40,000
5.15 % Series B due 2016	25,000	25,000
7.00 % Series B due 2017	40,000	40,000
6.60 % Series B due 2018	22,000	22,000
8.31 % Series B due 2019	10,000	10,000
7.63 % Series B due 2019	20,000	20,000
5.37 % Series B due 2020	75,000	75,000
9.05 % Series A due 2021	10,000	10,000
3.176 % Series B due 2021	50,000	50,000
3.542% Series B due 2023	50,000	50,000
5.62 % Series B due 2023	40,000	40,000
7.72 % Series B due 2025	20,000	20,000
6.52 % Series B due 2025	10,000	10,000
7.05 % Series B due 2026	20,000	20,000
7.00 % Series B due 2027	20,000	20,000
6.65 % Series B due 2027	19,700	19,700
6.65 % Series B due 2028	10,000	10,000
7.74 % Series B due 2030	20,000	20,000
7.85 % Series B due 2030	10,000	10,000
5.82 % Series B due 2032	30,000	30,000
5.66 % Series B due 2033	40,000	40,000
5.25 % Series B due 2035	10,000	10,000
4.00 % due 2042	50,000	50,000
	641,700	701,700
Subsidiary Senior Secured Debt		

Gill Ranch debt due 2016	20,000	40,000
	661,700	741,700
Less: Current maturities	40,000	60,000
Total long-term debt	$621,700	$681,700

First Mortgage Bonds
NW Natural issued $50 million of FMBs on August 19, 2013 with a coupon rate of 3.542% and a 10-year maturity.

Subsidiary Senior Secured Debt
Gill Ranch has $20 million of fixed-rate senior secured debt outstanding, which was issued in 2011 with a maturity date of November 30, 2016 and an interest rate of 7.75%.

Under the debt agreements, Gill Ranch is subject to certain covenants and restrictions including, but not limited to, a financial covenant that requires Gill Ranch to maintain minimum adjusted earnings before interest, taxes, depreciation, and amortization (EBITDA) at various levels over the term of the debt. As part of an amended agreement, the EBITDA covenant requirement is suspended through March 31, 2015 with lower EBITDA hurdles thereafter. The debt service reserve requirement was fixed at $3 million.

Retirements of Long-Term Debt
The utility redeemed $50 million of FMBs with a coupon rate of 3.95% in July 2014 and $10 million in September 2014 with a coupon rate of 8.26%. In June 2014, under the amended agreement Gill Ranch retired $20 million of variable interest rate debt with a coupon rate of 7.00%.

Fair Value of Long-Term Debt
Our outstanding debt does not trade in active markets. We estimate the fair value of our debt using utility companies with similar credit ratings, terms, and remaining maturities to our debt that actively trade in public markets. These valuations are based on Level 2 inputs as defined in the fair value hierarchy. See Note 2.

The following table provides an estimate of the fair value of our long-term debt, including current maturities of long-term debt, using market prices in effect on the valuation date:

	December 31,	
In thousands	2014	2013
Carrying amount	$661,700	$741,700
Estimated fair value	756,808	806,359

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8. PENSION AND OTHER POSTRETIREMENT BENEFIT COSTS

We maintain a qualified non-contributory defined benefit pension plan, non-qualified supplemental pension plans for eligible executive officers and other key employees, and other postretirement employee benefit plans. We also have qualified defined contribution plans (Retirement K Savings Plan) for all eligible employees. The qualified defined benefit pension plan and Retirement K Savings Plan have plan assets, which are held in qualified trusts to fund retirement benefits. Effective January 1, 2007 and 2010, the qualified defined benefit retirement plans and postretirement benefits for non-union employees and union employees, respectively, were closed to new participants. These plans were not available to employees of our non-utility subsidiaries. Non-union and union employees hired or re-hired after December 31, 2006 and 2009, respectively, and employees of NW Natural subsidiaries are provided an enhanced Retirement K Savings Plan benefit.

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, excluding the Retirement K Savings Plan, and a summary of the funded status and amounts recognized in the consolidated balance sheets as of December 31:

	Postretirement Benefit Plans			
	Pension Benefits		Other Benefits	
In thousands	2014	2013	2014	2013
Reconciliation of change in benefit obligation:				
Obligation at January 1	$391,089	$435,889	$28,754	$33,119
Service cost	7,213	8,698	483	656
Interest cost	18,198	16,400	1,252	1,157
Net actuarial (gain) loss	90,710	(51,043)	3,454	(4,283)
Benefits paid	(19,932)	(18,855)	(1,871)	(1,895)
Obligation at December 31	$487,278	$391,089	$32,072	$28,754
Reconciliation of change in plan assets:				
Fair value of plan assets at January 1	$267,062	$249,603	$—	$—
Actual return on plan assets	19,957	22,872	—	—
Employer contributions	12,077	13,442	1,871	1,895
Benefits paid	(19,932)	(18,855)	(1,871)	(1,895)
Fair value of plan assets at December 31	$279,164	$267,062	$—	$—
Funded status at December 31	$(208,114)	$(124,027)	$(32,072)	$(28,754)

Our qualified defined benefit pension plan has an aggregate benefit obligation of $451.2 million and $362.4 million at December 31, 2014 and 2013, respectively, and fair values of plan assets of $279.2 million and $267.1 million, respectively.

The following table presents amounts realized through regulatory assets or in other comprehensive loss (income) for the years ended December 31:

	Regulatory Assets						Other Comprehensive Loss (Income)		
	Pension Benefits			Other Postretirement Benefits			Pension Benefits		
In thousands	2014	2013	2012	2014	2013	2012	2014	2013	2012
Net actuarial loss (gain)	$83,027	$(51,892)	$26,504	$3,454	$(4,283)	$3,182	$7,221	$(3,302)	$3,511
Amortization of:									
Transition obligation	—	—	—	—	—	(411)	—	—	—

Prior service cost	(230)	(230)	(230)	(197)	(197)	(197)	7	7	35
Actuarial loss	(9,823)	(16,744)	(14,482)	(221)	(733)	(435)	(1,091)	(1,550)	(1,150)
Total	$72,974	$(68,866)	$11,792	$3,036	$(5,213)	$2,139	$6,137	$(4,845)	$2,396

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The following table presents amounts recognized in regulatory assets and accumulated other comprehensive loss (AOCL) at December 31:

	Regulatory Assets				AOCL	
	Pension Benefits		Other Postretirement Benefits		Pension Benefits	
In thousands	2014	2013	2014	2013	2014	2013
Prior service cost	$637	$867	$488	$685	$2	$(5)
Net actuarial loss	192,846	119,638	7,898	4,665	16,604	10,475
Total	$193,483	$120,505	$8,386	$5,350	$16,606	$10,470

The following table presents amounts recognized in AOCL and the changes in AOCL related to our non-qualified employee benefit plans:

	Year Ended December 31,	
In thousands	2014	2013
Beginning balance	$(6,358)	$(9,291)
Amounts reclassified to AOCL	(7,221)	3,302
Amounts reclassified from AOCL:		
Amortization of prior service costs	(7)	(7)
Amortization of actuarial losses	1,091	1,550
Total reclassifications before tax	(6,137)	4,845
Tax (benefit) expense	2,419	(1,912)
Total reclassifications for the period	(3,718)	2,933
Ending balance	$(10,076)	$(6,358)

In 2015, an estimated $17.0 million will be amortized from regulatory assets to net periodic benefit costs, consisting of $16.6 million of actuarial losses, and $0.4 million of prior service costs. A total of $2.2 million will be amortized from AOCL to earnings related to actuarial losses.

Our assumed discount rate for the pension plan and other postretirement benefit plans was determined independently based on the Citigroup Above Median Curve (discount rate curve), which uses high quality corporate bonds rated AA- or higher by S&P or Aa3 or higher by Moody’s. The discount rate curve was applied to match the estimated cash flows in each of the Company's plans to reflect the timing and amount of expected future benefit payments for these plans.

Our assumed expected long-term rate of return on plan assets for the qualified pension plan was developed using a weighted average of the expected returns for the target asset portfolio. In developing the expected long-term rate of return assumption, consideration was given to the historical performance of each asset class in which the plans’ assets are invested and the target asset allocation for plan assets.

Our investment strategy and policies for qualified pension plan assets held in the retirement trust fund were approved by our retirement committee, which is composed of senior management with the assistance of an outside investment consultant. The policies set forth the guidelines and objectives governing the investment of plan assets. Plan assets are invested for total return with appropriate consideration for liquidity, portfolio risk, and return expectations. All investments are expected to satisfy the prudent investments rule under the Employee Retirement Income Security Act of 1974. The approved asset classes may include cash and short-term investments, fixed income, common stock and convertible securities, absolute and real

return strategies, real estate, and investments in NW Natural securities. Plan assets may be invested in separately managed accounts or in commingled or mutual funds. Investment re-balancing takes place periodically as needed, or when significant cash flows occur, in order to maintain the allocation of assets within the stated target ranges. Our expected long-term rate of return is based upon historical index returns by asset class, adjusted by a factor based on our historical return experience, diversified asset allocation and active portfolio management by professional investment managers. The retirement trust fund is not currently invested in NW Natural securities.

The following table presents the pension plan asset target allocation at December 31, 2014:

Asset Category	Target Allocation	
U.S. large cap equity	18.0	%
U.S. small/mid cap equity	10.0	
Non-U.S. equity	18.0	
Emerging markets equity	5.0	
Long government/credit	20.0	
High yield bonds	5.0	
Emerging market debt	5.0	
Real estate funds	7.0	
Absolute return strategy	12.0	

Our non-qualified supplemental defined benefit plan obligations were $36.1 million and $28.7 million at December 31, 2014 and 2013, 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 AOCL, net of tax until they are amortized as a component of net periodic

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benefit cost. These are unfunded, non-qualified plans with no plan assets; however, we indirectly fund a portion of our obligations with company- and trust-owned life insurance and other assets.

Our other postretirement benefit plans are unfunded plans but are subject to regulatory deferral. The actuarial gains and losses, prior service costs, and transition assets or obligations for these plans are recognized as a regulatory asset.

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

The following table provides the components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
In thousands	2014	2013	2012	2014	2013	2012
Service cost	$7,213	$8,698	$8,047	$483	$656	$592
Interest cost	18,198	16,400	17,295	1,252	1,157	1,267
Expected return on plan assets	(19,496)	(18,721)	(19,082)	—	—	—
Amortization of transition obligations	—	—	—	—	—	411
Amortization of prior service costs	223	223	195	197	197	197
Amortization of net actuarial loss	10,914	18,294	15,631	221	734	435
Net periodic benefit cost	17,052	24,894	22,086	2,153	2,744	2,902
Amount allocated to construction	(4,625)	(6,712)	(5,820)	(702)	(856)	(882)
Amount deferred to regulatory balancing account[1]	(4,578)	(9,115)	(7,876)	—	—	—
Net amount charged to expense	$7,849	$9,067	$8,390	$1,451	$1,888	$2,020

(1) The deferral of certain pension expenses above or below the amount set in rates was approved by the OPUC, with recovery of these deferred amounts through the implementation of a balancing account, which includes the expectation of lower net periodic benefit costs in future years. Deferred pension expense balances include accrued interest at the utility's authorized rate of return, with the equity portion of the interest being deferred until amounts are collected in rates. See Note 2.

Net periodic benefit costs are reduced by amounts capitalized to utility plant based on approximately 25% to 35% payroll overhead charge. In addition, a certain amount of net periodic benefit costs are recorded to the regulatory balancing account for pensions. Net periodic pension cost less amounts charged to capital accounts and regulatory balancing accounts are expenses recognized in earnings.

The following table provides the assumptions used in measuring periodic benefit costs and benefit obligations for the years ended December 31:

	Pension Benefits			Other Postretirement Benefits		
	2014	2013	2012	2014	2013	2012
Assumptions for net periodic benefit cost:						
Weighted-average discount rate	4.71%	3.84%	4.51%	4.45%	3.56%	4.33%
Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50%	7.50%	8.00%	n/a	n/a	n/a

Assumptions for year-end funded status:						
Weighted-average discount rate	3.85 %	4.73 %	3.85 %	3.74 %	4.45 %	3.56 %
Rate of increase in compensation	3.25-5.0%	3.25-5.0%	3.25-5.0%	n/a	n/a	n/a
Expected long-term rate of return	7.50 %	7.50 %	7.50 %	n/a	n/a	n/a

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The assumed annual increase in health care cost trend rates used in measuring other postretirement benefits as of December 31, 2014 was 8.00% for pre-65 and 11.75% for post-65 populations. These trend rates apply to both medical and prescription drugs. Medical costs and prescription drugs are assumed to decrease gradually each year to a rate of 4.75% by 2022.

Assumed health care cost trend rates can have a significant effect on the amounts reported for the health care plans; however, other postretirement benefit plans have a cap on the amount of costs reimbursable from the Company. A one percentage point change in assumed health care cost trend rates would have the following effects:

In thousands	1% Increase	1% Decrease
Effect on net periodic postretirement health care benefit cost	$62	$(55)
Effect on the accumulated postretirement benefit obligation	1,260	(965)

The Company adopted a new set of mortality tables for its plans beginning with 2014. The tables were released in October 2014 by the Society of Actuaries' Retirement Plans Experience Committee and project a mortality improvement, thereby increasing benefit plan liabilities.

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

In thousands	Pension Benefits	Other Benefits
Employer Contributions:		
2013	$13,907	$1,895
2014	12,077	1,871
2015 (estimated)	16,567	1,848
Benefit Payments:		
2012	18,195	1,971
2013	18,855	1,895
2014	19,932	1,871
Estimated Future Benefit Payments:		
2015	20,315	1,848
2016	20,993	1,918
2017	21,784	1,955
2018	22,799	2,007
2019	24,162	2,075
2020-2024	137,839	10,412

Employer Contributions to Company-Sponsored Defined Benefit Pension 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. The Pension Protection Act of 2006 (the Act) established funding requirements for defined benefit plans. The Act establishes a 100% funding target over seven years for plan years beginning after December 31, 2008. In 2012 the Moving Ahead for Progress in the 21st Century Act

(MAP-21) legislation changed several provisions affecting pension plans, including temporary funding relief and Pension Benefit Guaranty Corporation (PBGC) premium increases, which reduces the level of minimum required contributions in the near-term but generally increases contributions in the long-run and increases the operational costs of running a pension plan. In 2014, the Highway and Transportation Funding Act (HATFA) was signed and extends certain aspects of MAP-21 as well as modifies the phase-out periods for the limitations.

Our qualified defined benefit pension plan is currently underfunded by $172.0 million at December 31, 2014. Including the impacts of MAP-21 and HATFA, we made cash contributions totaling $10.5 million to our qualified defined benefit pension plan for 2014. During 2015, we expect to make contributions of approximately $15 million to this plan.

Multiemployer Pension Plan

In addition to the Company-sponsored defined benefit plans presented above, prior to 2014 we contributed to a multiemployer pension plan for our utility's union employees known as the Western States Office and Professional Employees International Union Pension Fund (Western States Plan). The plan's employer identification number is 94-6076144. Effective December 22, 2013, we withdrew from the plan, which was a noncash transaction. Vested participants will receive all benefits accrued through the date of withdrawal. As the plan was underfunded at the time of withdrawal, we were assessed a withdrawal liability of $8.3 million, plus interest, which requires NW Natural to pay $0.6 million each year to the plan for 20 years beginning in July 2014. The cost of the withdrawal liability was deferred to a regulatory account on the balance sheet.

We made payments of $0.4 million for 2014 and as of December 31, 2014 the liability balance was $8.1 million. For 2013 and 2012, contributions to the plan were $0.5 million and $0.4 million, respectively, which was approximately 4% to 5% of the total contributions to the plan by all employer participants in those years.

Defined Contribution Plan

The Retirement K Savings Plan is a qualified defined contribution plan under Internal Revenue Code Section 401(k). Employer contributions totaled $3.4 million for 2014 and $2.2 million for both 2013 and 2012. The Retirement K Savings Plan includes an Employee Stock Ownership Plan.

Deferred Compensation Plans

The supplemental deferred compensation plans for eligible officers and senior managers are non-qualified plans. These plans are designed to enhance the retirement savings of employees and to assist them in strengthening their financial security by providing an incentive to save and invest regularly.

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

U.S. LARGE CAP EQUITY and U.S. SMALL/MID CAP EQUITY. These are level 1 and 2 assets. The level 1 assets consist of directly held stocks and mutual funds with a readily determinable fair value, including a published net asset value (NAV). The level 2 assets consist of mutual funds where NAV is not published but the investment can be readily disposed of at NAV or market value. Directly held stocks are valued at the closing price reported in the active market on which the individual security is traded, and mutual funds are valued at NAV. This asset class includes investments primarily in U.S. common stocks.

NON-U.S. EQUITY. These are level 1 and 2 assets. The level 1 assets consist of directly held stocks, and the level 2 assets consist of an open-end mutual fund and a commingled trust where the NAV/unit price is not published but the investment can be readily disposed of at the NAV/unit price. Directly held stocks are valued at the closing price reported in the active market on which the individual security is traded, and the mutual fund is valued at NAV, while the commingled trust is valued at the unit price of the trust. This asset class includes investments primarily in foreign equity common stocks.

EMERGING MARKETS EQUITY. This is a level 2 asset consisting of an open-end mutual fund where the NAV price is not published but the investment can be readily disposed of at the NAV. This asset class includes investments primarily in common stocks in emerging markets.

FIXED INCOME. This is a level 2 asset consisting of a mutual fund, valued at NAV, where NAV is not published, but the investment can be readily disposed of at NAV. This asset class includes investments primarily in investment grade debt and fixed income securities.

LONG GOVERNMENT/CREDIT. These are level 1 and 2 assets. The level 1 assets consist of a fixed-income mutual fund with readily determinable fair value, including a published NAV. The level 2 assets consist of directly held fixed-income securities whose values are determined by closing prices if available and by matrix prices for illiquid securities. This asset class includes long duration fixed income investments primarily in U.S. treasuries, U.S. government agencies, municipal securities, mortgage-backed securities, asset-backed securities, as well as U.S. and international investment-grade corporate bonds.

HIGH YIELD BONDS. These are level 2 assets consisting of a limited partnership where valuation is not published but the investment can be readily disposed of at market value. This asset class includes investments primarily in high yield bonds.

EMERGING MARKET DEBT. These are level 1 assets consisting of a mutual fund with a readily determinable fair value, including a published NAV. This asset class includes investments primarily in emerging market debt.

REAL ESTATE FUNDS. These are level 1 assets consisting of a mutual fund with a readily determinable fair value, including a published NAV. This asset class includes investments primarily in real estate investment trust (REIT) equity securities globally.

ABSOLUTE RETURN STRATEGY. These are level 2 assets consisting of a hedge fund of funds where valuations are not published but the investment can be readily disposed of at unit price. The hedge fund of funds is valued at the weighted average value of investments in various hedge funds, which in turn are valued at the closing price of the underlying securities. This asset class primarily includes investments in common stocks and fixed income securities.

REAL RETURN STRATEGY. These are level 1 assets representing a mutual fund with a readily determinable fair value, including a published NAV. This asset class includes an investment in a broad range of assets primarily including fixed income, high-yield bonds, and emerging market debt.

CASH AND CASH EQUIVALENTS. These are level 2 assets representing mutual funds without published NAV's but the investment can be readily disposed of at NAV. The mutual funds are valued at the NAV of the shares held by the plan at the valuation date. This asset class primarily includes money market mutual funds.

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

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

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The following table presents the fair value of plan assets, including outstanding receivables and liabilities, of the retirement trust fund:

In thousands	December 31, 2014			
Investments	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$39,405	$122	$—	$39,527
U.S. small/mid cap equity	27,172	85	—	27,257
Non-U.S. equity	16,369	17,221	—	33,590
Emerging markets equity	—	7,145	—	7,145
Fixed income	—	598	—	598
Long government/credit	40,584	40,235	—	80,819
High yield bonds	—	13,087	—	13,087
Emerging market debt	9,133	—	—	9,133
Real estate funds	18,890	—	—	18,890
Absolute return strategy	—	37,065	—	37,065
Real return strategy	8,308	—	—	8,308
Cash and cash equivalents	—	1,720	—	1,720
Total investments	$159,861	$117,278	$—	$277,139

	December 31, 2013			
Investments	Level 1	Level 2	Level 3	Total
U.S. large cap equity	$39,124	$79	$—	$39,203
U.S. small/mid cap equity	30,465	55	—	30,520
Non-U.S. equity	16,782	17,202	—	33,984
Emerging markets equity	7,405	—	—	7,405
Fixed income	—	367	—	367
Long government/credit	33,152	32,763	—	65,915
High yield bonds	—	12,890	—	12,890
Emerging market debt	9,987	—	—	9,987
Real estate funds	16,559	—	—	16,559
Absolute return strategy	—	35,339	—	35,339
Real return strategy	13,031	—	—	13,031
Cash and cash equivalents	—	1,418	—	1,418
Total investments	$166,505	$100,113	$—	$266,618

	December 31,	
Receivables	2014	2013
Accrued interest and dividend income	$510	$468
Due from broker for securities sold	1,694	1,154
Total receivables	$2,204	$1,622
Liabilities		
Due to broker for securities purchased	$179	$1,178
Total investment in retirement trust	$279,164	$267,062

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9. INCOME TAX

The following table provides a reconciliation between income taxes calculated at the statutory federal tax rate and the provision for income taxes reflected in the consolidated statements of comprehensive income for December 31:

Dollars in thousands	2014	2013	2012
Income taxes at federal statutory rate	$35,117	$35,785	$35,764
Increase (decrease):			
Current state income tax, net of federal tax benefit	4,666	4,674	4,773
Amortization of investment tax credits	(201)	(271)	(350)
Differences required to be flowed-through by regulatory commissions	2,357	2,357	1,718
Gains on company and trust-owned life insurance	(689)	(864)	(800)
Regulatory asset impairment	—	—	2,700
Other, net	393	24	(402)
Total provision for income taxes	$41,643	$41,705	$43,403
Effective tax rate	41.5%	40.8%	42.5%

The increase in the effective income tax rate for 2014 compared to 2013 was primarily the result of a $0.6 million income tax charge in 2014 related to a higher statutory tax rate in Oregon, which required the revaluation of deferred tax balances. The decrease in the effective income tax rate for 2013 compared to 2012 was primarily the result of an after-tax charge of $2.7 million in 2012 related to the OPUC's rate case order that the Company could not recover from customers the increase in deferred tax liabilities resulting from the 2009 Oregon income tax rate increase.

The provision (benefit) for current and deferred income taxes consists of the following at December 31:

In thousands	2014	2013	2012
Current			
Federal	$14,823	$(62)	$1,693
State	24	(11)	99
	14,847	(73)	1,792
Deferred			
Federal	18,635	35,109	31,187
State	8,161	6,669	10,424
	26,796	41,778	41,611
Total provision for income taxes	$41,643	$41,705	$43,403
Total income taxes paid	$19,445	$870	$2,979

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

In thousands	2014	2013	2012
Utility:			
Current	$24,317	$(73)	$1,909
Deferred	19,518	38,073	39,163
Deferred investment tax credits	(201)	(271)	(350)
	43,634	37,729	40,722
Non-utility business segments:			
Current	(9,470)	—	(117)

Deferred	7,479	3,976	2,798
	(1,991)	3,976	2,681
Total provision for income taxes	$41,643	$41,705	$43,403

The following table summarizes the tax effect of significant items comprising our deferred income tax accounts at December 31:

In thousands	2014	2013
Deferred tax liabilities:		
Plant and property	$386,732	$362,160
Regulatory income tax assets	51,805	56,183
Regulatory liabilities	55,776	71,971
Non-regulated deferred tax liabilities	48,683	47,516
Total	$542,996	$537,830
Deferred tax assets:		
Pension and postretirement obligations	$6,537	$4,112
Alternative minimum tax credit carryforward	16,788	1,939
Loss and credit carryforwards	12,657	45,351
Total	35,982	51,402
Deferred income tax liabilities, net	507,014	486,428
Deferred investment tax credits	166	367
Deferred income taxes and investment tax credits	$507,180	$486,795

Management assesses the available positive and negative evidence to estimate if sufficient taxable income will be generated to utilize the existing deferred tax assets. Based upon this assessment, we have determined we are more likely than not to realize all deferred tax assets recorded as of December 31, 2014.

The Company estimates it has net operating loss (NOL) carryforwards of $28.8 million for federal taxes and $49.4 million for Oregon taxes at December 31, 2014. We anticipate fully utilizing these NOL carryforward balances before they begin to expire in 2033 for federal and 2027 for Oregon. Alternative minimum tax (AMT) credits of $16.8 million, general business credits of $0.2 million, and charitable contribution carryforwards of $4.6 million are also available. The AMT credits do not expire, and we anticipate fully utilizing the general business credits and charitable contribution carryforwards before they begin to expire in 2033 and 2015, respectively.

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As a result of certain realization requirements prescribed in the accounting guidance for income taxes, the tax benefit of statutory depletion is recognized no earlier than the year in which the depletion is deductible on the Company's federal income tax return. Income tax expense will be decreased by approximately $0.9 million if and when the deferred depletion from 2013 and 2014 is realized.

Uncertain tax positions are accounted for in accordance with accounting standards that require management's assessment of the anticipated settlement outcome of material uncertain tax positions taken in a prior year, or planned to be taken in the current year. Until such positions are sustained, we would not recognize the uncertain tax benefits resulting from such positions. No reserves for uncertain tax positions existed as of December 31, 2014, 2013, or 2012.

The Company's examination by the Internal Revenue Service (IRS) for tax years 2009 through 2011 was completed during the first quarter of 2014. The examination did not result in a material change to the returns as originally filed or previously adjusted for net operating loss carrybacks. The 2013 and 2014 tax years are currently in examination under the IRS Compliance Assurance Process (CAP). The Company's 2015 tax year CAP application has been accepted by the IRS. Under the CAP program the Company works with the IRS to identify and resolve material tax matters before the tax return is filed each year. As of December 31, 2014, tax year 2012 remains open for federal examination.

In 2012 the Company settled the Oregon Department of Revenue examination of tax years 2006 through 2009. This settlement resulted in an additional $0.2 million state tax expense, including interest, but was offset by a corresponding refund claim with the state of California. As of December 31, 2014, tax years 2011 through 2014 are open for Oregon examination.

10. PROPERTY, PLANT, AND EQUIPMENT

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

In thousands	2014	2013
Utility plant in service	$2,661,097	$2,585,901
Utility construction work in progress	24,886	28,855
Less: Accumulated depreciation	836,510	827,380
Utility plant, net	1,849,473	1,787,376
Non-utility plant in service	297,295	297,330
Non-utility construction work in progress	9,282	6,653
Less: Accumulated depreciation	34,457	28,485
Non-utility plant, net	272,120	275,498
Total property, plant, and equipment	$2,121,593	$2,062,874
Capital expenditures in accrued liabilities	$8,757	$10,691

The weighted average depreciation rate was 2.8% for utility assets and 2.2% for non-utility assets in 2014, 2013, and 2012.

Accumulated depreciation does not include the accumulated provision for asset removal costs of $311.2 million and $296.3 million at December 31, 2014 and 2013, respectively. These accrued asset removal costs are reflected on the balance sheets as regulatory liabilities. See Note 2. In addition, we acquired equipment under capital leases of $1.3 million and $0.2 million in 2014 and 2013, respectively.

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11. GAS RESERVES

Our gas reserves are stated at cost, net of regulatory amortization, with the associated deferred tax benefits recorded as liabilities on the balance sheet.

We entered into agreements with Encana Oil & Gas (USA) Inc. (Encana) in 2011 to develop and produce physical gas reserves and provide long-term gas price protection for utility customers. Encana began drilling in 2011 under these agreements. Gas produced from working interests in these gas fields is sold at prevailing market prices, with revenues from such sales, less associated production costs, credited to the utility's cost of gas. The cost of gas, including a carrying cost for the rate base investment, is part of NW Natural's annual Oregon PGA filing, which allows us to recover our costs through customer rates. Our net investment under the original agreement earns a rate of return and provides long-term price protection for our utility customers.

On March 28, 2014, we amended the original gas reserve agreement in order to facilitate Encana's proposed sale of its interest in the Jonah field to Jonah Energy LLC. Under the amendment, we ended the drilling program with Encana, but increased our assigned ownership interests in certain sections of the Jonah field and retained the right to invest in additional wells with the new owner.

Since the amendment, we have been notified by Jonah Energy LLC of investment opportunities in the sections of the Jonah field where we have ownership interests. The amended agreement allows us to invest in additional wells on a well-by-well basis with drilling costs and resulting gas volumes shared at our amended proportionate ownership interest for each well in which we invest. We elected to participate in some of the additional wells drilled in 2014, and we may have the opportunity to participate in more wells in the future. We filed an application requesting regulatory deferral in Oregon for these additional investments. We have also signed a memorandum of understanding with all parties agreeing that individual wells drilled in any year will be reviewed for prudence annually going forward. Subsequently, we filed in 2015 seeking cost recovery for the additional wells drilled in 2014. A decision on the prudence of the wells drilled in 2014 will occur when the parties and Commission review our filing seeking cost recovery. Our cumulative investment of approximately $10 million in these additional wells has been accounted for as a utility investment. If regulatory approval is not received, our investment in these additional wells would follow oil and gas accounting.

Gas reserves acted to hedge the cost of gas
for approximately 10% and 6% of our utility's gas supplies for the years ended December 31, 2014 and 2013, respectively.

The following table outlines our net gas reserves investment at December 31:

In thousands	2014	2013
Gas reserves, current	$20,020	$20,646
Gas reserves, non-current	167,190	140,573
Less: Accumulated amortization	37,910	18,575
Total gas reserves[(1)]	149,300	142,644
Less: Deferred taxes on gas reserves	18,551	42,117
Net investment in gas reserves[(1)]	$130,749	$100,527

(1) Total gas reserves includes our investment in additional wells, subject to regulatory deferral approvals, with total gas reserves of $9.2 million and net investment of $8.4 million at December 31, 2014 and no net investment or total gas reserves from additional wells in 2013.

Variable Interest Entity (VIE) Analysis

We concluded that the arrangement with Encana qualifies as a variable interest (VI) as our interest represents a minor portion of total extraction activities. Our investment is included on our balance sheet under gas reserves with our maximum loss exposure limited to our current investment balance.

12. INVESTMENTS

Investments include financial investments in life insurance policies, which are accounted for at cash surrender value, net of policy loans, and equity investments in certain partnerships and limited liability companies, which are accounted for under the equity method. The following table summarizes our other investments at December 31:

In thousands	2014	2013
Investments in life insurance policies	$52,366	$51,791
Investments in gas pipeline	13,962	14,048
Other	1,910	2,012
Total other investments	$68,238	$67,851

Investment in Life Insurance Policies

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

Investments in Gas Pipeline

Trail West Pipeline, LLC (TWP), a wholly-owned subsidiary of TWH, is pursuing the development of a new gas transmission pipeline that would provide an interconnection with our utility distribution system. NWN Energy, a wholly-owned subsidiary of NW Natural owns 50% of TWH, and 50% is owned by TransCanada American Investments Ltd., an indirect wholly-owned subsidiary of TransCanada Corporation.

VIE Analysis

TWH is a development stage VIE, with our investment in TWP reported under equity method accounting. We have determined we are not the primary beneficiary of TWH’s

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activities, in accordance with the authoritative guidance related to consolidations, as we only have a 50% share of the entity and there are no stipulations that allow us a disproportionate influence over it. Our investment in TWH and TWP are included in other investments on our balance sheet. Should this investment not be developed, then our maximum loss exposure related to TWH is limited to our equity investment balance, less our share of any cash or other assets available to us as a 50% owner. Our investment balance in TWH was $13.4 million at December 31, 2014 and 2013.

Impairment Analysis

Our investments in nonconsolidated entities accounted for under the equity method are reviewed for impairment at each reporting period and following updates to our corporate planning assumptions. If it is determined that a loss in value is other than temporary, a charge is recognized for the difference between the investment’s carrying value and its estimated fair value. Fair value is based on quoted market prices when available or on the present value of expected future cash flows. Differing assumptions could affect the timing and amount of a charge recorded in any period.

In 2011, TWP withdrew its original application with the FERC for a proposed natural gas pipeline in Oregon and informed FERC that it intended to re-file an application to reflect changes in the project scope aligning the project with the region’s current and future gas infrastructure needs. TWP continues working with customers in the Pacific Northwest to further understand their gas transportation needs and determine the commercial support for a revised pipeline proposal. A new FERC certificate application is expected to be filed to reflect a revised scope based on these regional needs.

Our equity investment was not impaired at December 31, 2014 as the fair value of expected cash flows from planned development exceeded our remaining equity investment of $13.4 million at December 31, 2014. However, if we learn that the project is not viable or will not go forward, then we could be required to recognize a maximum charge of up to approximately $13.3 million based on the current amount of our equity investment, net of cash and working capital at TWP. We will continue to monitor and update our impairment analysis as required.

13. DERIVATIVE INSTRUMENTS

We enter into financial derivative contracts to hedge a portion of our utility’s natural gas sales requirements. These contracts include swaps, options, and combinations of option contracts. We primarily use these derivative financial instruments to manage commodity price variability. A small portion of our derivative hedging strategy involves foreign currency exchange contracts.

We enter into these financial derivatives, up to prescribed limits, primarily to hedge price variability related to our physical gas supply contracts as well as to hedge spot purchases of natural gas. The foreign currency forward contracts are used to hedge the fluctuation in foreign currency exchange rates for pipeline demand charges paid in Canadian dollars.

In the normal course of business, we also enter into indexed-price physical forward natural gas commodity purchase contracts and options to meet the requirements of utility customers. These contracts qualify for regulatory deferral accounting treatment.

We also enter into exchange contracts related to the third-party asset management of our gas portfolio, some of which are derivatives that do not qualify for hedge accounting or regulatory deferral, but are subject to our regulatory sharing agreement.

Notional Amounts

The following table presents the absolute notional amounts related to open positions on our derivative instruments:

	At December 31,	
In thousands	2014	2013
Natural gas (in therms):		
Financial	287,475	389,225
Physical	420,980	552,500
Foreign exchange	$12,230	$15,002

PGA

As of November 1, 2014, we reached our target hedge percentage for the 2014-15 gas year, and these hedge prices were included in the PGA filing and qualified for regulatory deferral.

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Unrealized and Realized Gain/Loss

The following table reflects the income statement presentation for the unrealized gains and losses from our derivative instruments:

	December 31, 2014		December 31, 2013	
In thousands	Natural gas commodity	Foreign exchange	Natural gas commodity	Foreign exchange
Benefit (expense) to cost of gas	$(32,784)	$(382)	$4,985	$(300)
Less:				
Amounts deferred to regulatory accounts on balance sheet	32,782	382	(4,964)	300
Total gain (loss) in pre-tax earnings	$(2)	$—	$21	$—

Outstanding derivative instruments related to regulated utility operations are deferred in accordance with regulatory accounting standards. The cost of foreign currency forward and natural gas derivative contracts are recognized immediately in the cost of gas; however, costs above or below the amount embedded in the current year PGA are subject to a regulatory deferral tariff and therefore, are recorded as a regulatory asset or liability.

We realized net gains of $10.5 million and net losses of $11.0 million for the years ended December 31, 2014 and 2013, respectively, from the settlement of natural gas financial derivative contracts. Realized gains and losses are recorded in cost of gas, deferred through our regulatory accounts, and amortized through customer rates in the following year.

Credit Risk Management of Financial Derivatives Instruments

No collateral was posted with or by our counterparties as of December 31, 2014 or 2013. We attempt to minimize the potential exposure to collateral calls by counterparties to manage our liquidity risk. Counterparties generally allow a certain credit limit threshold before requiring us to post collateral against loss positions. Given our counterparty credit limits and portfolio diversification, we have not been subject to collateral calls in 2014 or 2013. Our collateral call exposure is set forth under credit support agreements, which generally contain credit limits. We could also be subject to collateral call exposure where we have agreed to provide adequate assurance, which is not specific as to the amount of credit limit allowed, but could potentially require additional collateral in the event of a material adverse change.

Based upon current financial swap and option contracts outstanding, which reflect unrealized losses of $30.6 million at December 31, 2014, we have estimated the level of collateral demands, with and without potential adequate assurance calls, using current gas prices and various credit downgrade rating scenarios for NW Natural as follows:

		Credit Rating Downgrade Scenarios			
In thousands	(Current Ratings) A+/A3	BBB+/Baa1	BBB/Baa2	BBB-/Baa3	Speculative
With Adequate Assurance Calls	$—	$—	$4	$2,504	$27,150
Without Adequate Assurance Calls	—	—	—	—	19,646

Our financial derivative instruments are subject to master netting arrangements; however, they are presented on a gross basis in our statement of financial position. The Company and its counterparties have the ability to set-off their obligations to each other under specified circumstances. Such circumstances may include a defaulting party, a credit change due to a merger affecting either party, or any other termination event.

If netted by counterparty, our derivative position would result in an asset of $0.2 million and a liability of $33.4 million as of December 31, 2014. As of December 31, 2013, our derivative position would have resulted in an asset of $7.2 million and a liability of $2.5 million.

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

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

We actively monitor our derivative credit exposure and place counterparties on hold for trading purposes or require other forms of credit assurance, such as letters of credit, cash collateral or guarantees as circumstances warrant. Our ongoing assessment of counterparty credit risk includes consideration of credit ratings, credit default swap spreads, bond market credit spreads, financial condition, government actions, and market news. We use a Monte-Carlo simulation model to estimate the change in credit and liquidity risk from

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the volatility of natural gas prices. The results of the model are used to establish earnings-at-risk trading limits. Our credit risk for all outstanding financial derivatives at December 31, 2014 extends to March 2017.

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

Fair Value

In accordance with fair value accounting, we include non-performance risk in calculating fair value adjustments. This includes a credit risk adjustment based on the credit spreads of our counterparties when we are in an unrealized gain position, or on our own credit spread when we are in an unrealized loss position. The inputs in our valuation models include natural gas futures, volatility, credit default swap spreads, and interest rates. Additionally, our assessment of non-performance risk is generally derived from the credit default swap market and from bond market credit spreads. The impact of the credit risk adjustments for all outstanding derivatives was immaterial to the fair value calculation at December 31, 2014. As of December 31, 2014 and 2013, the net fair value was a liability of $33.2 million and an asset of $4.7 million, respectively, using significant other observable, or level 2, inputs. No level 3 inputs were used in our derivative valuations, and there were no transfers between level 1 or level 2 during the years ended December 31, 2014 and 2013. See Note 2.

14. COMMITMENTS AND CONTINGENCIES

Leases

We lease land, buildings, and equipment under agreements that expire in various years, including a 99-year land lease that extends through 2108. Rental expense under operating leases was $5.9 million, $5.1 million, and $4.8 million for the years ended December 31, 2014, 2013, and 2012, respectively. The following table reflects the future minimum lease payments due under non-cancelable leases at December 31, 2014. These commitments relate principally to the lease of our office headquarters, underground gas storage facilities, and computer equipment.

In thousands	Operating leases	Capital leases	Minimum lease payments
2015	$5,487	$680	$6,167
2016	5,457	564	6,021
2017	5,426	157	5,583
2018	5,301	3	5,304
2019	5,209	—	5,209
Thereafter	29,802	—	29,802
Total	$56,682	$1,404	$58,086

Gas Purchase and Pipeline Capacity Purchase and Release Commitments

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

The aggregate amounts of these agreements were as follows at December 31, 2014:

In thousands	Gas Purchase Agreements	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2015	$132,382	$80,925	$3,379
2016	—	79,211	—
2017	—	58,827	—
2018	—	50,792	—
2019	—	26,686	—
Thereafter	—	205,313	—
Total	132,382	501,754	3,379
Less: Amount representing interest	93	76,748	4
Total at present value	$132,289	$425,006	$3,375

Our total payments for fixed charges under capacity purchase agreements were $94.3 million for 2014, $98.2 million for 2013, and $94.3 million for 2012. Included in the amounts were reductions for capacity release sales of $4.8 million for 2014, $4.5 million for 2013, and $4.2 million for 2012. 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

See Note 15 for a discussion of environmental commitments and contingencies.

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15. ENVIRONMENTAL MATTERS

We own, or previously owned, properties that may require environmental remediation or action. We estimate the range of loss for environmental liabilities based on current remediation 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. Due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several site investigations, in some cases, we may not be able to reasonably estimate the high end of the range of possible loss. In those cases, we have disclosed the nature of the possible loss and the fact that the high end of the range cannot be reasonably estimated. Unless there is an estimate within a range of possible losses that is more likely than other cost estimates within that range, we record the liability at the low end of this range. It is likely that changes in these estimates and ranges will occur throughout the remediation process for each of these sites due to our continued evaluation and clarification concerning our responsibility, the complexity of environmental laws and regulations and the determination by regulators of remediation alternatives.

In the 2012 Oregon general rate case, the SRRM mechanism was approved to recover the Company's deferred environmental costs. The Commission ordered a separate docket to determine the prudence of deferred costs, the allocation of insurance proceeds, and an earnings test that would be applied to past and future deferred costs. This separate docket was resolved in February 2015. See Note 16 for information regarding the resolution of this matter.

In Washington, the Company is authorized to defer environmental costs, if any, that are appropriately allocated to Washington customers. The cost recovery and carrying charges on amounts deferred for costs associated with services provided to Washington customers will be determined in a future proceeding. Annually, the Company reviews all regulatory assets for recoverability or more often if circumstances warrant. If we should determine all or a portion of these regulatory assets no longer meet the criteria for continued application of regulatory accounting, then we would be required to write off the net unrecoverable balances against earnings in the period such determination is made.

In December 2010, NW Natural commenced litigation against certain of its historical liability insurers in Multnomah County Circuit Court, State of Oregon. In February 2014, we settled with remaining defendant insurance companies and received additional payments of approximately $103 million. The Court dismissed the case on July 29, 2014. The Company has received total proceeds of approximately $150 million as a result of this litigation. The proceeds are recognized in regulatory accounts with the treatment determined under the SRRM. See Note 16.

Environmental Sites

The following table summarizes information regarding liabilities related to environmental sites, which are recorded in other current liabilities and other noncurrent liabilities on the balance sheet at December 31:

	Current Liabilities		Non-Current Liabilities	
In thousands	2014	2013	2014	2013
Portland Harbor site:				
Gasco/Siltronic Sediments	$1,767	$1,278	$38,019	$37,954
Other Portland Harbor	1,934	1,766	4,338	3,478
Gasco Upland site	9,535	11,010	37,117	39,508
Siltronic Upland site	957	763	348	406
Central Service Center site	171	85	—	248
Front Street site	1,020	1,274	122	122
Oregon Steel Mills	—	—	179	179

Total	$15,384	$16,176	$80,123	$81,895

The following table presents information regarding the total amount of cash paid for environmental sites and the total regulatory asset deferred as of December 31:

In thousands	2014	2013
Cash paid[1]	$113,740	$98,817
Total regulatory asset deferral[2]	58,859	148,389

(1) Includes $20.4 million reclassified to utility plant on November 1, 2013 associated with the water treatment station of which a portion was paid during 2012 through 2014.

(2) Includes cash paid, remaining liability, and interest, net of insurance reimbursement and amounts reclassified to utility plant for the water treatment station.

PORTLAND HARBOR SITE. The Portland Harbor is an Environmental Protection Agency (EPA) listed Superfund site that is approximately 10 miles long on the Willamette River and is adjacent to NW Natural's Gasco uplands and Siltronic uplands sites. We have been notified that we are a potentially responsible party to the Superfund site and we have joined with some of the other potentially responsible parties (the Lower Willamette Group or LWG) to develop a Portland Harbor Remedial Investigation/Feasibility Study

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(RI/FS). The LWG submitted a draft Feasibility Study (FS) to the EPA in March 2012 providing a range of remedial costs for the entire Portland Harbor Superfund Site, which includes the Gasco/Siltronic Sediment site, discussed below. The range of costs estimated for various remedial alternatives for the entire Portland Harbor, as provided in the draft FS, is $169 million to $1.8 billion. NW Natural's potential liability is a portion of the costs of the remedy the EPA will select for the entire Portland Harbor Superfund site. The cost of that remedy is expected to be allocated among more than 100 potentially responsible parties. NW Natural is participating in a non-binding allocation process in an effort to settle this potential liability. We manage our liability related to the Superfund site as two distinct remediation projects, the Gasco/Siltronic Sediments and Other Portland Harbor projects.

Gasco/Siltronic Sediments. In 2009, NW Natural and Siltronic Corporation entered into a separate Administrative Order on Consent with the EPA to evaluate and design specific remedies for sediments adjacent to the Gasco uplands and Siltronic uplands sites. NW Natural submitted a draft Engineering Evaluation/Cost Analysis (EE/CA) to the EPA in May 2012 to provide the estimated cost of potential remedial
alternatives for this site. At this time, the estimated costs for the various sediment remedy alternatives in the draft EE/CA as well as costs for the additional studies and design work needed before the clean-up can occur, and for regulatory oversight throughout the clean-up range from $39.8 million to $350 million. We have recorded a liability of $39.8 million for the sediment clean-up, which reflects the low end of the range. At this time, we believe sediments at this site represent the largest portion of our liability related to the Portland Harbor site, discussed above.

Other Portland Harbor. NW Natural incurs costs related to its membership in the LWG which is performing the RI/FS for the EPA. NW Natural also incurs costs related to natural resource damages from these sites. The Company and other parties have signed a cooperative agreement with the Portland Harbor Natural Resource Trustee council to participate in a phased natural resource damage assessment to estimate liabilities to support an early restoration-based settlement of natural resource damage claims. Natural resource damage claims may arise only after a remedy for clean-up has been settled. We have accrued a liability for these claims which is at the low end of the range of the potential liability; the high end of the range cannot be reasonably estimated at this time. This liability is not included in the range of costs provided in the draft FS for the Portland Harbor and noted above.

GASCO UPLANDS SITE. NW Natural owns a former gas manufacturing plant that was closed in 1958 (Gasco site) and is adjacent to the Portland Harbor site described above. The Gasco site has been under investigation by us for environmental contamination under the ODEQ Voluntary Clean-Up Program. It is not included in the range of remedial costs for the Portland Harbor site noted above. We manage the Gasco site in two parts, the uplands portion and the groundwater source control action.
In May 2007, we completed a revised Remedial Investigation Report for the uplands portion and submitted it to ODEQ for review. We have recognized a liability for the

remediation of the uplands portion of the site which is at the low end of the range of potential liability; the high end of the range cannot be reasonably estimated at this time.

In September 2013, we completed construction of a groundwater source control system, including a water treatment station, at the Gasco site. We are working with ODEQ on monitoring the effectiveness of the system and at this time it is unclear what, if any, additional actions ODEQ may require subsequent to the initial testing of the system or as part of the final remedy for the uplands portion of the Gasco site. We have estimated the cost associated with the ongoing operation of the system and have recognized a liability which is at the low end of the range of potential cost. We cannot estimate the high end of the range at this time due to the uncertainty associated with the duration of running the water treatment station, which is highly dependent on the remedy determined for both the upland portion as well as the final remedy for our Gasco sediment exposure.

Beginning November 1, 2013, capital asset costs of $19.0 million for the Gasco water treatment station were placed into rates with OPUC approval. The OPUC deemed these costs prudent. Beginning November 1, 2014, the OPUC approved the application of $2.5 million from insurance proceeds plus interest to reduce the total amount of Gasco capital costs to be recovered through rate base. A portion of these proceeds was noncash in 2014.

OTHER SITES. In addition to those sites above, we have environmental exposures at four other sites: Siltronic, Central Service Center, Front Street, and Oregon Steel Mills. Due to the uncertainty of the design of remediation, regulation, timing of the liabilities, and in the case of the Oregon Steel Mills site, pending litigation, liabilities for each of these sites have been recognized at their respective low end of the range of potential liability; the high end of the range could not be reasonably estimated as of December 31, 2014.

SILTRONIC UPLAND. A portion of the Siltronic property was formerly owned by NW Natural as part of the adjacent Gasco site. We are currently conducting an investigation of manufactured gas plant wastes on the uplands at this site for the ODEQ.

Central Service Center site. We are currently performing an environmental investigation of the property under the ODEQ's Independent Cleanup Pathway. This site is on ODEQ's list of sites with confirmed releases of hazardous substances, and cleanup is necessary.

Front Street site. The Front Street site was the former location of a gas manufacturing plant we operated. NW Natural is currently developing a feasibility study to support ODEQ's evaluation of potential clean-up alternatives.

Oregon Steel Mills site. See “Legal Proceedings,” below.

Legal Proceedings

NW Natural is subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings cannot be predicted with

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certainty, including the matter described below, NW Natural does not expect that the ultimate disposition of any of these matters will have a material effect on our financial condition, results of operations or cash flows. See also Part I, Item 3, “Legal Proceedings.”

OREGON STEEL MILLS SITE. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (the Port) in a Multnomah County Circuit Court case, Oregon Steel Mills, Inc. v. The Port of Portland. The Port alleges that in the 1940s and 1950s petroleum wastes generated by our predecessor, Portland Gas & Coke Company, and 10 other third-party defendants, were

disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Oregon Steel Mills. The complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. No date has been set for trial. Although the final outcome of this proceeding cannot be predicted with certainty, we do not expect the ultimate disposition of this matter will have a material effect on our financial condition, results of operations or cash flows.

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16. SUBSEQUENT EVENT

As previously disclosed, in NW Natural's 2012 Oregon general rate case, the OPUC adopted a Site Remediation and Recovery Mechanism (SRRM), through which NW Natural would track and recover past deferred and future environmental remediation costs. The OPUC ordered a separate docket to determine the following items:

- whether and how an earnings test should affect the recovery of already deferred environmental expenses,
- how an earnings test should apply to the recovery of future environmental expenditures through the SRRM,
- how to apply insurance proceeds received to offset past and/or future environmental expenses, and
- the prudence of environmental expenses and insurance recoveries.

On February 20, 2015, the OPUC issued an Order addressing these outstanding items. In the Order, the OPUC determined that NW Natural's environmental remediation expenses and associated carrying costs through March 31, 2014 were prudently incurred, and the Company's settlement with insurance carriers resulting in insurance proceeds received was prudent.

The Order also approves the allocation of environmental costs between states based on historical manufactured gas usage with approximately 97% allocated to Oregon and 3% to Washington customers.

Under the Order, NW Natural will be required to forego collection of $15 million out of the approximate $95 million of environmental expenses and associated carrying costs that it had deferred through 2012. The OPUC disallowed this amount from rate recovery based on its determination of how an earnings test should apply to amounts deferred from 2003 to 2012, with adjustments for factors the OPUC deemed relevant. The disallowance is currently estimated to result in a net after-tax charge of $9.1 million taken through operating income in the first quarter of 2015.

The OPUC applied one-third of the Company's approximately $150 million of environmental insurance recoveries to amounts deferred through 2012, and will allow full recovery of the remainder of the amounts deferred through 2012, other than the disallowed amount discussed above and approximately $33 thousand, which the OPUC found was not specifically substantiated by company records. The remaining insurance recoveries will be applied against post-2012 environmental costs with the funds to be held in an account accruing interest with the interest also applied to future expenses as outlined below.

The Order establishes all environmental remediation expenses deferred after 2012, an aggregate of two-thirds of the environmental insurance receipts, plus interest, will be applied ratably over 20 years and the remainder will be collected through the SRRM, and subject to an earnings test as follows:

- The Company will recover the first $5 million of annual expense through an amount that will be collected from customers through a tariff rider.
- The Company will apply $5 million of insurance (plus interest) to the next portion of environmental expenses each year.
- Any amounts in excess of the annual $10 million (plus interest from insurance) described above would be fully recoverable through the SRRM, to the extent the utility earns at or below its authorized Return On Equity (ROE). To the extent the Company earns more than its authorized ROE in a year, the Company would be required to cover environmental expenses greater than the $10 million (plus interest from insurance) with those earnings that exceed its authorized ROE.
- For purposes of this earnings test, all earnings derived from utility assets, including gains and losses associated with NW Natural's weighted average cost of gas incentive mechanism, plus 50% of the Company's earnings derived from the Company's portion of its asset management agreement with our independent energy marketing company for asset management services associated with utility assets will be included.
-

In any year that environmental expenses are less than $10 million (plus the interest on insurance), any unused tariff rider amount will offset deferred amounts otherwise collected through the SRRM and any unused insurance proceeds (plus interest on insurance) will roll forward to offset the next year's expenses.

- Any remaining funds will be used to offset environmental remediation costs at the end of the project.

The Company is evaluating the results of the Order, including those noted above as well as the state allocations. At this time, the Company does not anticipate a disallowance for 2013 or 2014 based on the earnings test outlined above.

In accordance with accounting guidance and the Company's policy, the Company expects to recognize net deferred interest income of approximately $4 million pre-tax on the associated regulatory account balances in the first quarter of 2015.

Under the Order, the OPUC will revisit the deferral and amortization of future remediation expenses, as well as the treatment of remaining insurance proceeds in three years, or earlier if the Company gains greater certainty about its future remediation costs.

The Company continues to evaluate the effects of the Order and is required to file a compliance report with the OPUC within 30 days of the Order demonstrating how it will be implemented. The compliance filing is subject to review and approval by the OPUC and, as a consequence thereof, additional or different implementation procedures could be required, which may, among other things, result in additional impacts on earnings. The Company anticipates filing the compliance report as required by the Order in March 2015.

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NORTHWEST NATURAL GAS COMPANY
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

In thousands, except share data	Quarter ended March 31	June 30	September 30	December 31
2014				
Operating revenues	$293,386	$133,169	$87,199	$240,283
Net income (loss)	37,884	1,071	(8,733)	28,470
Basic earnings (loss) per share[1]	1.40	0.04	(0.32)	1.05
Diluted earnings (loss) per share[1]	1.40	0.04	(0.32)	1.04
2013				
Operating revenues	$277,861	$131,714	$88,195	$260,748
Net income (loss)	37,639	2,126	(8,233)	29,006
Basic earnings (loss) per share[1]	1.40	0.08	(0.31)	1.07
Diluted earnings (loss) per share[1]	1.40	0.08	(0.31)	1.07

(1) Quarterly earnings (loss) per share are based upon the average number of common shares outstanding during each quarter. Variations in earnings between quarterly periods are due primarily to the seasonal nature of our business.

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

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions		Deductions	
In thousands (year ended December 31)	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Net write-offs	Balance at end of period
2014					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$1,656	$599	$—	$1,286	$969
2013					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$2,518	$199	$—	$1,061	$1,656
2012					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$2,895	$1,130	$—	$1,507	$2,518

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

Our management, under the supervision and with the participation of our Chief Executive Officer and Chief Financial Officer, has completed an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act)). Based upon this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that, as of the end of the period covered by this report, our disclosure controls and procedures were effective to ensure that information required to be disclosed by us and included in our reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the Securities

and Exchange Commission (SEC) rules and forms and that such information is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

(b) Changes in Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in the Exchange Act Rule 13a-15(f).

There have been no changes in our internal control over financial reporting that occurred during the quarter ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. The statements contained in Exhibit 31.1 and Exhibit 31.2 should be considered in light of, and read together with, the information set forth in this Item 9(a).

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The "Information Concerning Nominees and Continuing Directors", "Corporate Governance", and "Section 16(a) Beneficial Ownership Reporting Compliance" contained in our definitive Proxy Statement for the May 28, 2015 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2014	Positions held during last five years
Gregg S. Kantor	57	President and Chief Executive Officer (2009-); President and Chief Operating Officer (2007-2008); Executive Vice President (2006-2007); Senior Vice President, Public and Regulatory Affairs (2003-2006).
David H. Anderson	53	Executive Vice President and Chief Operating Officer (2014-); Executive Vice President Operations and Regulation (2013-2014); Senior Vice President and Chief Financial Officer (2004-2013).
Stephen P. Feltz	59	Senior Vice President and Chief Financial Officer (2013-); Assistant Secretary (2007-); Treasurer and Controller (1999-2013).
Margaret D. Kirkpatrick	60	Senior Vice President, Environmental Policy and Affairs (2015-); Senior Vice President and General Counsel (2013-2014); Vice President and General Counsel (2005-2013).
Lea Anne Doolittle	59	Senior Vice President and Chief Administrative Officer (2013-); Senior Vice President (2008-); Vice President, Human Resources (2000-2007).
MardiLyn Saathoff	58	Senior Vice President and General Counsel (2015-); Vice President Legal, Risk and Compliance (2013-2014); Deputy General Counsel (2010-2013); Chief Governance Officer and Corporate Secretary (2008-2014);
David R. Williams	61	Vice President, Utility Services (2007-); Director of Utility Operations, Districts and Managed Labor Relations (2004-2006).
Grant M. Yoshihara	59	Vice President, Utility Operations (2007-); Managing Director, Utility Services (2005-2006); Director, Utility Services (2004-2005).
C. Alex Miller	57	Vice President Regulation and Treasurer (2013-); Vice President, Finance and Regulation (2009-2013); Assistant Treasurer (2008-2013); General Manager of Rates and Regulatory Affairs (2002-2009).
Shawn M. Filippi	42	Vice President and Corporate Secretary (2015-); Senior Legal Counsel (2011-2014); Assistant Corporate Secretary (2010-2014); Associate Legal Counsel (2005-2010).
Kimberly A. Heiting	45	Vice President, Communications and Chief Marketing Officer (2015-); Chief Marketing & Communications Officer (2013-2014); Chief Corporate Communications Officer (2011-2013); Communications Director (2005-2011).
Brody J. Wilson	35	Controller (2013-); Acting Controller (2013); Accounting Director (2012-2013); Senior Manager, PriceWaterhouseCoopers LLP (2009-2012); Manager, PriceWaterhouseCoopers LLP (2007-2009).

David A. Weber	55	President and Chief Executive Officer, NW Natural Gas Storage, LLC and Gill Ranch Storage, LLC (2012-); Interim President and Chief Executive Officer, NW Natural Gas Storage LLC, and Gill Ranch Storage, LLC (2011-2012); Chief Operating Officer NW Natural Gas Storage, LLC and Gill Ranch Storage LLC (November 2010 - January 2011); Managing Director of Information Services and Chief Information Officer (2005 - 2011); Director of Information Services and Chief Information Officer (2001-2005).

Each executive officer serves successive annual terms; present terms end on May 28, 2015. There are no family relationships among our executive officers, directors or any person chosen to become one of our officers or directors. NW Natural has adopted a Code of Ethics (Code) applicable to all employees and officers that is available on our website at www.nwnatural.com. We intend to disclose on our website at www.nwnatural.com any amendments to the Code or waivers of the Code for executive officers.

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ITEM 11. EXECUTIVE COMPENSATION

The information concerning "Executive Compensation", "Report of the Organization and Executive Compensation Committee", and "Compensation Committee Interlocks and Insider Participation" contained in our definitive Proxy Statement for the May 28, 2015 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of December 31, 2014 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, 2014 (see Note 6 to the Consolidated Financial Statements):

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
LTIP Performance Share Awards (Target Award)(1)(2)	116,265	n/a	412,728
LTIP Restricted Stock Units (Target Award)(1)(2)	70,794	n/a	412,728
LTIP Stock Options(2)	—	—	250,000
Restated Stock Option Plan	416,088	$43.40	—
Employee Stock Purchase Plan	22,646	38.90	75,275
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)(3)	1,292	n/a	n/a
Directors Deferred Compensation Plan (DDCP)(3)	51,559	n/a	n/a
Deferred Compensation Plan for Directors and Executives (DCP)(4)	134,283	n/a	n/a
Total	812,927		738,003

(1) Shares issued pursuant to Performance Share Awards and Restricted Stock Units under the LTIP do not include an exercise price, but are payable when the award criteria are satisfied. If the maximum awards were paid pursuant to the Performance Share Awards outstanding at December 31, 2014, the number of shares shown in column (a) would increase by 116,265 shares and the number of shares shown in column (c) would decrease by the same amount of shares.

(2) The aggregate 412,728 shares are available for future issuance under the LTIP as Restricted Stock Units, or Performance Share Awards. An additional 250,000 shares are available for LTIP Stock Option Issuance at December 31, 2014, but those additional shares are not available for issuance of LTIP Restricted Stock Units or Performance Share Awards.

(3) Prior to January 1, 2005, deferred amounts were credited, at the participant's election, to either a “cash account” or a “stock account.” If deferred amounts were credited to stock accounts, such accounts were credited with a number of shares of NW Natural common stock based on the purchase price of the common stock on the next purchase date

under our Dividend Reinvestment and Direct Stock Purchase Plan, and such accounts were credited with additional shares based on the deemed reinvestment of dividends. Cash accounts are credited quarterly with interest at a rate equal to Moody’s Average Corporate Bond Yield plus two percentage points, subject to a 6% 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. Amounts credited to stock accounts are payable solely in shares of common stock and cash for fractional shares, and amounts in the above table represent the aggregate number of shares credited to participant's stock accounts. We have contributed common stock to the trustee of the Umbrella Trusts such that the Umbrella Trusts hold approximately the number of shares of common stock equal to the number of shares credited to all participants’ stock accounts.

(4) Effective January 1, 2005, the EDCP and DDCP were closed to new participants and replaced with the DCP. The DCP continues the basic provisions of the EDCP and DDCP under which deferred amounts are credited to either a “cash account” or a “stock account.” Stock accounts represent a right to receive shares of NW Natural common stock on a deferred basis, and such accounts are credited with additional shares based on the deemed reinvestment of dividends. Effective January 1, 2007, cash accounts are credited quarterly with interest at a rate equal to Moody’s Average Corporate Bond Yield. Our obligation to pay deferred compensation in accordance with the terms of the DCP will generally become due on retirement, death, or other termination of service, and will be paid in a lump sum or in installments of five, 10, or 15 years as elected by the participant in accordance with the terms of the DCP. Amounts credited to stock accounts are payable solely in shares of common stock and cash for fractional shares, and amounts in the above table represent the aggregate number of shares credited to participant's stock accounts. We have contributed common stock to the trustee of the Supplemental Trust such that this trust holds approximately the number of common shares equal to the number of shares credited to all participants' stock accounts. The right of each participant in the DCP is that of a general, unsecured creditor of the Company.

The information captioned “Beneficial Ownership of Common Stock by Directors and Executive Officers” and "Security Ownership of Common Stock of Certain Beneficial Owners" contained in our definitive Proxy Statement for the May 28, 2015 Annual Meeting of Shareholders is incorporated herein by reference.

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

The information captioned "Transactions with Related Persons" and "Corporate Governance" in the Company's definitive Proxy Statement for the May 28, 2015 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned "2014 and 2013 Audit Firm Fees" in the Company's definitive Proxy Statement for the May 28, 2015 Annual Meeting of Shareholders is hereby incorporated by reference.

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PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

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

2. List of Exhibits filed:

Reference is made to the Exhibit Index commencing on page 92.

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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

By: /s/ Gregg S. Kantor
Gregg S. Kantor
President and Chief Executive Officer
Date: February 27, 2015

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

Signature	Title	Date
/s/ Gregg S. Kantor Gregg S. Kantor President and Chief Executive Officer	Principal Executive Officer and Director	February 27, 2015
/s/ Stephen P. Feltz Stephen P. Feltz Senior Vice President and Chief Financial Officer	Principal Financial Officer	February 27, 2015
/s/ Brody J. Wilson Brody J. Wilson Controller	Principal Accounting Officer	February 27, 2015
/s/ Timothy P. Boyle Timothy P. Boyle	Director	)))
/s/ Martha L. Byorum Martha L. Byorum	Director	)))
/s/ John D. Carter John D. Carter	Director	)))
/s/ Mark S. Dodson Mark S. Dodson	Director	)) February 27, 2015
/s/ C. Scott Gibson C. Scott Gibson	Director	))

		)
/s/ Tod R. Hamachek	Director	)
Tod R. Hamachek		)
		)
/s/ Jane L. Peverett	Director	)
Jane L. Peverett		)
		)
/s/ Kenneth Thrasher	Director	)
Kenneth Thrasher		)
/s/ Malia H. Wasson	Director	)
Malia H. Wasson		)

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NORTHWEST NATURAL GAS COMPANY
Exhibit Index to Annual Report on Form 10-K
For the Fiscal Year Ended December 31, 2014

Exhibit Number	Document
*3a.	Restated Articles of Incorporation, as filed and effective May 31, 2006 and amended June 3, 2008 (incorporated herein by reference to Exhibit 3.1 to Form 10-Q for the period ending June 30, 2008, File No. 1-15973).
*3b.	Bylaws as amended May 22, 2014 (incorporated herein by reference to Exhibit 3.1 to Form 8-K dated May 22, 2014, File No. 1-15973).
*4a.	Copy of Mortgage and Deed of Trust, dated as of July 1, 1946, to Bankers Trust and R. G. Page (to whom Stanley Burg is now successor), Trustees (incorporated herein by reference to Exhibit 7(j) in File No. 2-6494); and copies of Supplemental Indentures Nos. 1 through 14 to the Mortgage and Deed of Trust, dated respectively, as of June 1, 1949, March 1, 1954, April 1, 1956, February 1, 1959, July 1, 1961, January 1, 1964, March 1, 1966, December 1, 1969, April 1, 1971, January 1, 1975, December 1, 1975, July 1, 1981, June 1, 1985 and November 1, 1985 (incorporated herein by reference to Exhibit 4(d) in File No. 33-1929); Supplemental Indenture No. 15 to the Mortgage and Deed of Trust, dated as of July 1, 1986 (filed as Exhibit 4(c) in File No. 33-24168); Supplemental Indentures Nos. 16, 17 and 18 to the Mortgage and Deed of Trust, dated, respectively, as of November 1, 1988, October 1, 1989 and July 1, 1990 (incorporated herein by reference to Exhibit 4(c) in File No. 33-40482); Supplemental Indenture No. 19 to the Mortgage and Deed of Trust, dated as of June 1, 1991 (incorporated herein by reference to Exhibit 4(c) in File No. 33-64014); and Supplemental Indenture No. 20 to the Mortgage and Deed of Trust, dated as of June 1, 1993 (incorporated herein by reference to Exhibit 4(c) in File No. 33-53795).
*4b.	Copy of Indenture, dated as of June 1, 1991, between the Company and Bankers Trust Company, Trustee, relating to the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4(e) in File No. 33-64014).
*4c.	Officers' Certificate dated June 12, 1991 creating Series A of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4e. to Form 10-K for 1993, File No. 0-994).
*4d.	Officers' Certificate dated June 18, 1993 creating Series B of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4f. to Form 10-K for 1993, File No. 0-994).
*4e.	Officers' Certificate dated January 17, 2003 relating to Series B of the Company's Unsecured Medium-Term Notes and supplementing the Officers' Certificate dated June 18, 1993 (incorporated herein by reference to Exhibit 4f.(1) to Form 10-K for 2002, File No. 0-994).
*4f.	Form of 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).
*4g.	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).
*4h.	Gill Ranch Note Purchase Agreement, dated November 30, 2011, among Gill Ranch Storage, LLC and the parties listed thereto (incorporated herein by reference to Exhibit 4m. to Form 10-K for 2011, File No. 1-15973).

*4i.	Twenty-First Supplemental Indenture, providing, among other things, for First Mortgage Bonds, 4.00% Series Due 2042, dated as of October 15, 2012, by and between Northwest Natural Gas Company, Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), and Stanley Burg (Successor to R.G. Page and J.C. Kennedy) (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated October 26, 2012, File No.1-15973).
*4j.	Form of Credit Agreement among Northwest Natural Gas Company and the parties thereto, with JPMorgan Chase Bank, N.A. as administrative agent and U.S. Bank, N.A. and Wells Fargo Bank, N.A. as co-syndication agents, dated as of December 20, 2012 (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated December 20, 2012, File No.1-15973).

*4k.	Form of Letter Agreement, between each of JPMorgan Chase Bank, N.A., Bank of America, N.A., Canadian Imperial Bank of Commerce, Royal Bank of Canada, TD Bank, N.A., Union Bank, N.A., US Bank, N.A., and Wells Fargo Bank, N.A., with JPMorgan Chase Bank, N.A. as Administrative Agent, extending the Credit Agreement between Northwest Natural Gas Company and each financial institution, effective as of December 20, 2013. (incorporated herein by reference to Exhibit 4k to Form 10-K for 2013, File No. 1-15973).
*4l.	Amendment No. 1 to Note Purchase Agreement, dated April 29, 2014, among Gill Ranch Storage, LLC. and the parties listed thereto (incorporated herein by reference to Exhibit 4 to Form 10-Q for the quarter ended March 31, 2014, File No. 1-15973).
4m.	Form of Letter Agreement, between each of JPMorgan Chase Bank, N.A., Bank of America, N.A., Canadian Imperial Bank of Commerce, Royal Bank of Canada, TD Bank, N.A., Union Bank, N.A., US Bank, N.A., and Wells Fargo Bank, N.A., with JPMorgan Chase Bank, N.A. as Administrative Agent, extending the Credit Agreement between Northwest Natural Gas Company and each financial institution, effective as of December 20, 2014.
4n.	First Amendment to Credit Agreement, between the Company JPMorgan Chase Bank, N.A., Bank of America, N.A., Canadian Imperial Bank of Commerce, Royal Bank of Canada, TD Bank, N.A., Union Bank, N.A., US Bank, N.A., and Wells Fargo Bank, N.A., with JPMorgan Chase Bank, N.A. as Administrative Agent, dated as of December 20, 2014.
*10a	Carry and Earning Agreement (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2011, File No. 1-15973).
*10b	Second Amendment to Carry and Earning Agreement by and between Encana Oil and Gas (USA) Inc. and NWN Gas Reserves, LLC., dated as of March 7, 2014 (incorporated herein by reference to Exhibit 10 to Form 10-Q for the quarter ended March 31, 2014, File No. 1-15973).
12	Statement re computation of ratios of earnings to fixed charges.
21	Subsidiaries of Northwest Natural Gas Company.
23	Consent of PricewaterhouseCoopers LLP.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
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:

*10c.	Executive Supplemental Retirement Income Plan 2010 Restatement (incorporated herein by reference to Exhibit 10b. to Form 10-K for 2009, File No. 1-15973).
*10d.	

	Supplemental Executive Retirement Plan, effective September 1, 2004 restated 2011 (incorporated herein by reference to Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2011, File No. 1-15973).
*10e.	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).
*10f.	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).
*10g.	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).

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*10h.	Restated Stock Option Plan, as amended effective December 14, 2006 (incorporated herein by reference to Exhibit 10c. to Form 10-K for 2006, File No. 1-15973).
*10i.	Form of Restated Stock Option Plan Agreement (incorporated herein by reference to Exhibit 10h. to Form 10-K for 2009, File No. 1-15973).
*10j.	Executive Deferred Compensation Plan, effective as of January 1, 1987, restated as of February 26, 2009 (incorporated herein by reference to Exhibit 10e. to Form 10-K for 2008, File No. 1-15973).
*10k.	Directors Deferred Compensation Plan, effective June 1, 1981, restated as of February 26, 2009 (incorporated herein by reference to Exhibit 10f. to Form 10-K for 2008, File No. 1-15973).
*10l.	Deferred Compensation Plan for Directors and Executives effective January 1, 2005, restated as of January 1, 2012 (incorporated herein by reference to Exhibit 10k. to Form 10-K for 2011, File No. 1-15973).
*10m.	Form of Indemnity Agreement as entered into between the Company and each director and certain executive officers (incorporated herein by reference to Exhibit 10l. to Form 10-K for 2009, File No. 1-15973).
*10n.	Form of Indemnity Agreement as entered into between the Company and certain executive officers (incorporated herein by reference to Exhibit 10l.(1) to Form 10-K for 2009, File No. 1-15973).
*10o.	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).
*10p.	Executive Annual Incentive Plan, effective February 23, 2012 (incorporated herein by reference to Exhibit 10n. to Form 10-K for 2011, File No. 1-15973).
*10q.	Form of Agreement to Recoupment Provisions of Executive Annual Incentive Plan, effective as of January 1, 2010 (incorporated herein by reference to Exhibit 10o. to Form 10-K for 2009, File No. 1-15973).
*10r.	Form of Change in Control Severance Agreement between the Company and each executive officer (incorporated herein by reference to Exhibit 10o. to Form 10-K for 2008, File No. 1-15973).
*10s.	Northwest Natural Gas Company Long-Term Incentive Plan, as amended and restated effective May 24, 2012 (incorporated herein by reference to Exhibit 10r to Form 10-K for 2013, File No. 1-15973)
*10t.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (2012-2014) (incorporated herein by reference to Exhibit 10v. to Form 10-K for 2011, File No. 1-15973).
*10u.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (2013-2015) (incorporated herein by reference to Exhibit 10v. to Form 10K for 2012, File No. 1-15973).
*10v.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (2014-2016). (incorporated herein by reference to Exhibit 10v. to Form 10-K for 2013, File No. 1-15973).
10w.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (2015-2017).
*10x.	

	Form of Consent dated December 14, 2006 entered into by each executive officer (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 19, 2006, File No. 1-15973).
*10y.	Consent to Amendment of Deferred Compensation Plan for Directors and Executives, dated February 28, 2008 entered into by each executive officer (incorporated herein by reference to Exhibit 10bb to Form 10-K for 2007, File No. 1-15973).

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*10z.	Form of Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan (2013) (incorporated herein by reference to Exhibit 10aa. to Form 10-K for 2012, File No. 1-15978).
*10aa.	Form of Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan (2012) (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 14, 2011, File No. 1-15973).
*10bb.	Form of Special Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan between the Company and an executive officer (incorporated herein by reference to Exhibit 10cc. to Form 10-Q for the period ending September 30, 2013, File No. 1-15973)
*10cc.	Form of Special Restricted Stock Unit Award Agreement under the Long-Term Incentive Plan between the Company and an executive officer. (incorporated herein by reference to Form 10-Q for the quarter ended March 31, 2014, File No. 1-15973).
*10dd.	Annual Incentive Plan for NW Natural Gas Storage, LLC, as amended February 2, 2012 (incorporated herein by reference to Exhibit 10cc. to Form 10-K for 2012, File No. 1-15973).
*10ee.	Long Term Incentive Plan for NW Natural Gas Storage, LLC (incorporated herein by reference to Exhibit 10dd. to Form 10-K for 2012, File No. 1-15973).
101.	The following materials from Northwest Natural Gas Company Annual Report on Form 10-K for the fiscal year ended December 31, 2014, formatted in Extensible Business Reporting Language (XBRL): (i) Consolidated Statements of Income; (ii) Consolidated Balance Sheets; (iii) Consolidated Statements of Cash Flows; and (iv) Related notes.

*Incorporated herein by reference as indicated