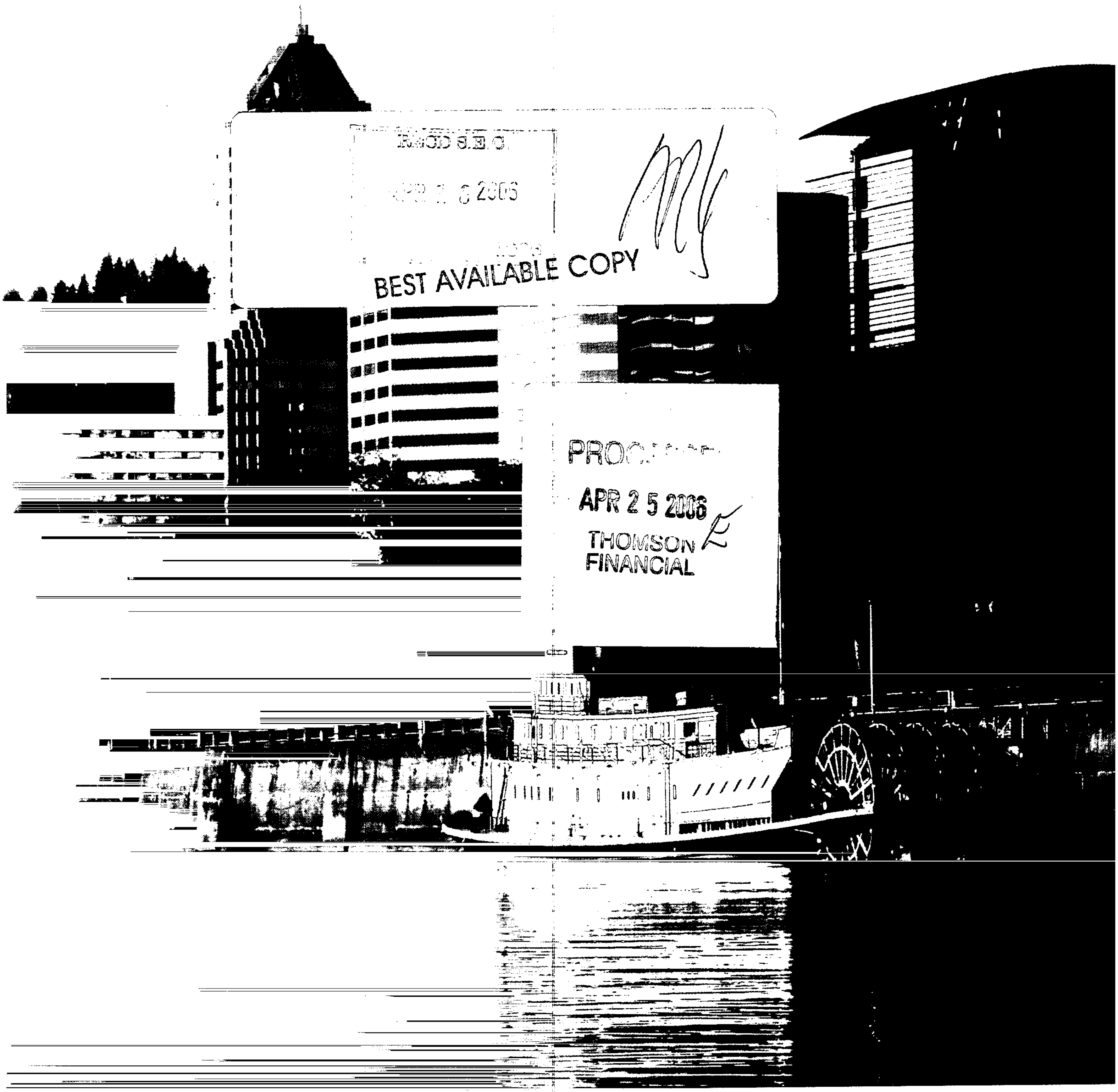
NW Natural®

2005 ANNUAL REPORT

Creating value



"We are ready for the challenges and opportunities that lie ahead. After 147 years, we remain delivering value for all those who have placed their

—Mark S. Dodson, President and Chief Executive Officer

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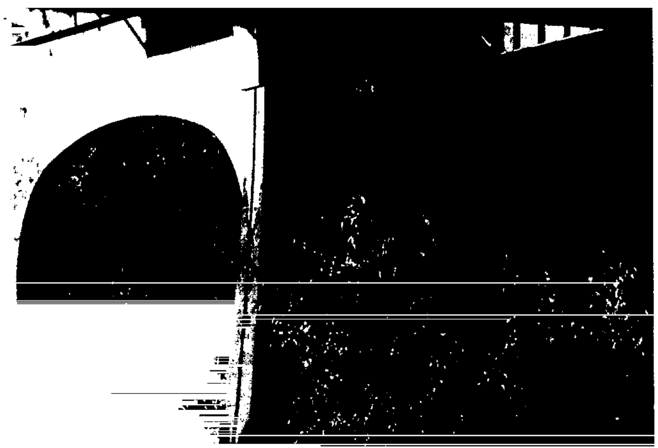
Mark Dodson, President and CEO, visits gas control in Portland. Gas controllers such as John Pigott monitor the Company's 13,000 miles of pipeline. The Gas Supply Department creates value by maximizing storage and transportation opportunities.

Creating value



At NW Natural, we know what we are after.

Value.

Value for our shareholders. Value for our customers. Value for our employees and our communities.

How we go about creating value is a mixture of art and science, like the graceful presentment of the right fly on the right riffle at the right time.

When our lead natural gas buyer looks at the market, he uses all the technological tools in his basket. But the tools can only take him so far and at some point he has to make a judgment. The way he wields his expertise creates value.

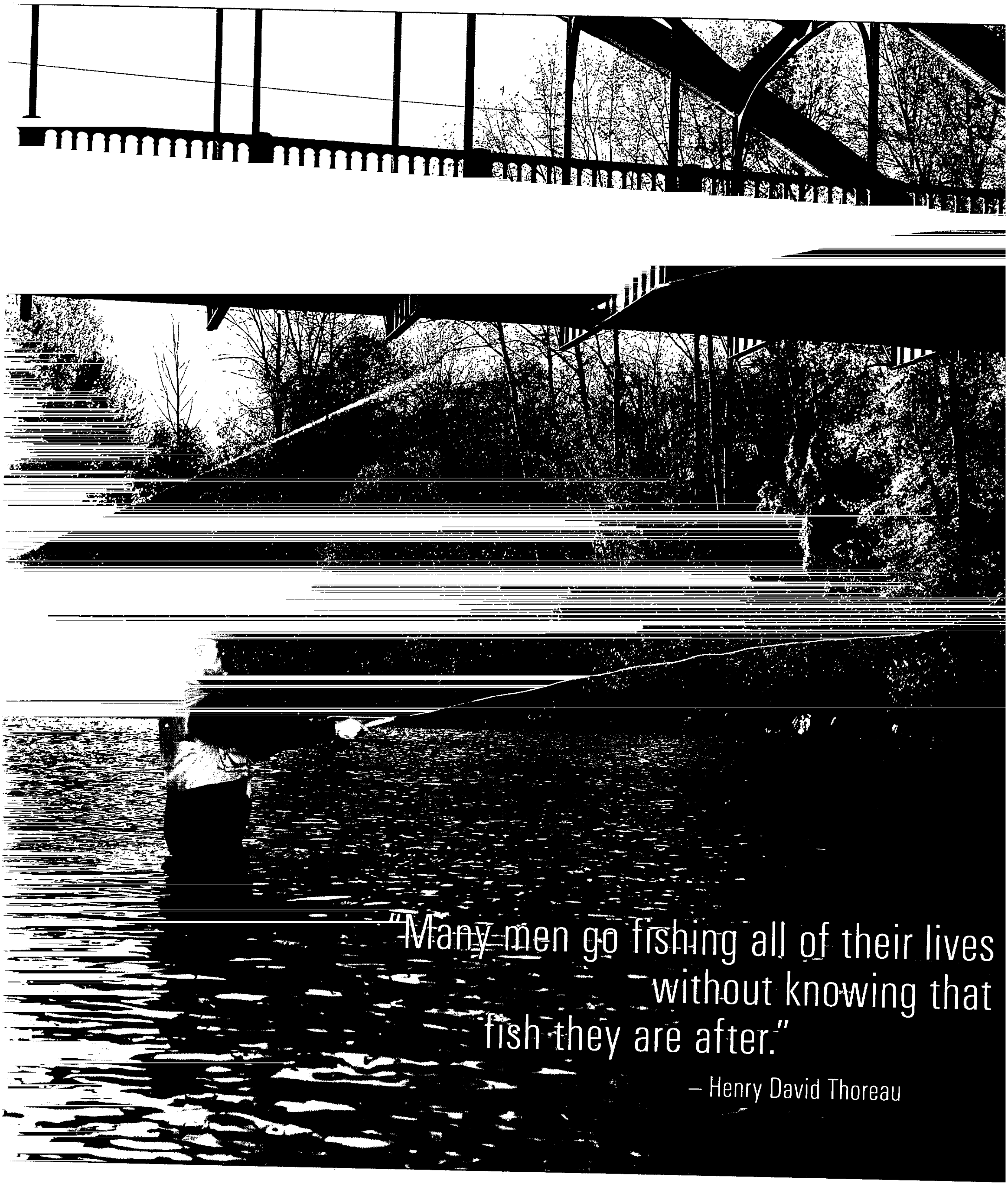
Managers scan operations with an eye for improving efficiency, striking the most effective balance between quality and cost. The right decisions create value by making new customers more profitable more quickly and by fostering a devoted work force.

Executives look up and downstream for opportunities and hazards. Where are the snags? Where are the best places to cast? Are there bigger fish somewhere else? Wisely navigating these issues creates value for shareholders, customers, employees and communities.

In 2005, we knew what we were after – and achieved it.

It is not


PO


"Many men go fishing all of their lives
without knowing that
fish they are after."
– Henry David Thoreau

Interview with the Chief Financial Officer

Q: How would you assess NW Natural's overall financial condition?

A: NW Natural is in excellent shape with a sound business strategy and a solid foundation for future growth. Our balance sheet, cash flows and our liquidity position remain strong. We continue to focus on strengthening our financial position and on profitable growth in our regulated gas distribution business and our interstate gas storage activities. We did well in 2005. We continued to improve our financial controls and our Sarbanes-Oxley compliance process. In addition, we are upgrading how we communicate with investors and interested parties. We also increased our dividends paid for the 50th consecutive year, something only a few companies can claim.

Q: What about NW Natural's long-term earnings growth?

A: Our 2005 results were the combination of a lot of hard work and excellent planning. As for the future, revenue mechanisms are in place to help offset declining usage and warm weather. Customer growth remains strong and our system is in excellent shape. Continued customer growth and interstate gas storage expansion are the main earnings drivers for 2006 and 2007, along with appropriate controls on capital and operating expenses. We continue to look for additional growth opportunities; for example, expanding to parts of our service territory we don't currently serve or adding additional storage capacity at our Mist fields. Our main financial goals are still to consistently produce returns greater than our cost of capital, to provide long-term earnings per share growth of 5 percent or more and to pay out 60 percent to 70 percent of earnings in the form of common dividends.

Q: How is NW Natural creating value?

A: For a number of years, we have had a sharp focus on improving the profitability of every customer we add. We've developed new technology to identify the most profitable customers and created cost-effective marketing programs to attract them. Clearly, strong organic growth opportunities exist in our system and we are working hard to maximize them. In addition to our core activities, we are continuing to create value through our interstate gas storage business. But we also believe that value comes from finding ways to make our operations more efficient and more effective. A great example is our Automated Meter Reading project. It will reduce operating costs immediately and will improve the accuracy of our billing systems. There is an initial capital investment, but the return is substantial, particularly in our smaller districts.

Q: Can you talk more about your operational model, how that might change, and what it might mean to the bottom line?

A: With the high price of natural gas and the effect that has on our customers, it is very important that our operational model be the best it can be. Specifically, our operations need to be designed to ensure that we safely, reliably and efficiently distribute natural gas to our customers. Our current operational model is good, but I also believe we can do better. We are thoroughly reviewing all aspects of our operations. I believe that review will produce cost savings and identify ways we can better serve the customer. We are working at this every day, gaining insight from our employees as well as our peers, and we expect these efforts to make a substantial difference in 2006 and beyond.

Q: What will the NW Natural of 2010 look like?

A: Since joining the Company in late 2004, my focus has been to see that our planning and budgeting processes were firmly in place to ensure we could look into the future with the clearest vision possible to see both opportunities and threats. Some days the vision is clearer than others, but the focus remains the same: look and plan for the future every day. Since 1990, we have doubled our customers while maintaining the same number of employees. In the next five years, we are looking to continue to grow our customer base. Assuming current growth rates that would take us to nearly three-quarters of a million customers by 2010. We plan to do that profitably by further improving our financial performance, continuing to become more efficient and making wise choices in a competitive market.

[illegible] Anderson, Senior Vice President and Chief Financial Officer, keeps Wall Street and investors apprised of NW Natural's current and future strategies.

high prices don't impede our growth. Accomplishing that means continuing to deliver more value to our customers and doing it more efficiently. As costs increase, so do customer expectations. Meeting those expectations while continuing to grow shareholder value has become a central focus of our business planning, one driving us to thoroughly re-examine how we structure our operations.

Looking Ahead, Making Changes Now

Last year, we launched an intensive effort to refresh the Company's Strategic Plan. We knew 2005 would be a good year, but recognized it was no time to rest on our laurels – it was an opportunity to look ahead and begin to address the challenges.

As part of our Strategic Plan update, teams of employees explored new ways to operate. They searched for efficiencies that would drive operating and capital costs down while delivering customers better overall value. The Company's senior management team met with every workgroup to describe the challenges ahead and gather ideas for change. The results of this work shaped our 2006 budget and fueled further examination.

We began 2006 looking hard at our peers in the gas industry, searching for best practices. We have committed ourselves to drive those best practices into our operations. We are looking at every opportunity, from outsourcing to investing in new technology. And we are making immediate changes.

For example, we are launching an Automated Meter Reading (AMR) project that will be phased in over the next few years. Initially, AMR will be introduced in our outlying areas. That's where the greatest cost savings are today. We are already planning for the reduction in meter-reading positions by using normal attrition and filling open positions with temporary employees.

Another initiative is the Service Solutions program we will launch this spring in the Portland-Vancouver area. This program is designed to strengthen relationships with residential customers and equipment dealers. Service Solutions connects customers who need furnace, water heater or fireplace repairs with a NW Natural-certified dealer. Dealers who participate are required to call the customer within two hours of receiving a request from NW Natural. This allows our technicians to work more efficiently and cut costs. The program will expand to our entire service territory this fall.

As these examples demonstrate, we are using 2006 to re-examine NW Natural's core operations and make changes to position the Company for the future. To continue to create value we must continually evaluate and improve our operational model. In some areas this means working very differently from the past. Our employees are committed to, and involved in, this process. They understand the challenges and recognize we have an obligation to our customers, shareholders and the communities we serve to adopt the best practices in our industry.

NW Natural and its employees understand that without strong and healthy communities our Company could not succeed. Certainly our efforts to deliver natural gas safely, reliably and cost effectively strengthen our communities. But we are also committed to contributing in other ways that make a difference. This last year the Company gave major contributions to such important causes as Oregon Food Bank, Habitat for Humanity, LifeWorks Northwest and SMART (Start Making A Reader Today). We also supported dozens of local programs in which our employees are leaders or volunteers. And employees themselves stepped up and answered the call by helping to raise nearly $100,000 for hurricane victims as part of the Company's Annual Charitable Giving Campaign, setting a new record for overall employee giving of $208,000. In many ways, we reached out to the communities we serve this past year, adding value that improved people's lives.

Committed to Creating Value

Shareholders, customers, employees and communities have all profited from a year of accomplishment. We can also say with continued confidence that by planning ahead, working hard and executing with precision, we will continue to create value.

Last year I wrote: *We know who we are. We know where we're going. We know what you expect from us, and we know how to deliver.*

I believe that more strongly than ever. We're ready for the opportunities that lie ahead. We'll adapt to the changing business environment and position the Company for strong results in the future. And we'll never stop looking ahead of the next curve to anticipate and meet challenges.

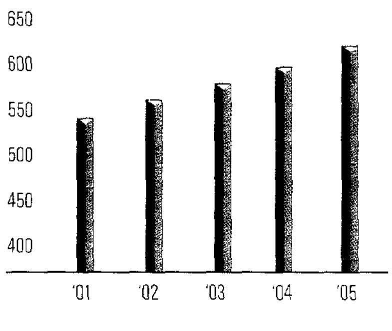
Most of all, after 147 years, we know one thing never changes: our commitment to delivering value for all of those who have placed their confidence in us. Thank you for your trust in NW Natural, and we look forward to continuing to work on your behalf.

Sincerely,

Mark S. Dodson

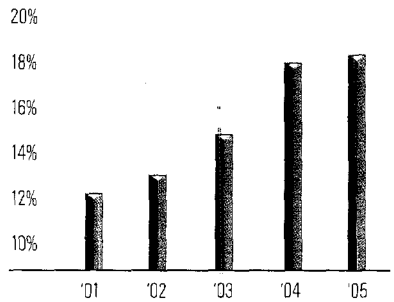
Mark S. Dodson
President and Chief Executive Officer
March 1, 2006

Total Customers
IN THOUSANDS



The Company added 20,528 new customers in 2005, expanding our customer base by 3.4 percent. In the past five years, the Company has added almost 100,000 new customers.

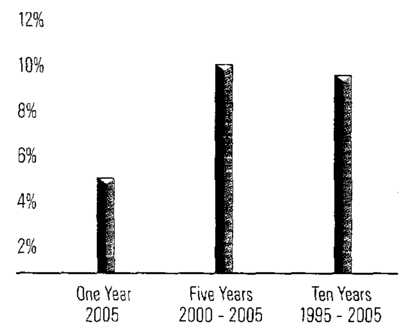
Profitability of New Residential Customer Acquisitions*
IN PERCENT RETURN ON EQUITY



NW Natural continues to improve its returns from new residential customers by targeting the most profitable customers and managing main extension costs.

* *Average margin per customer less incremental costs.*

Total Shareholder Return
ANNUALIZED AS A PERCENT



The Company's annualized total return – dividends plus stock appreciation – was 5.1 percent in 2005, 10 percent over the past five years, and 9.6 percent over 10 years.

We were pleased with what we accomplished, but we also knew that a 15 percent increase would still be tough on many of our customers. So we stepped up our efforts to help customers better manage higher prices. Among other things, we launched a redesigned Web site with new tools to help customers analyze and cut energy costs. We also ran television ads to draw attention to these tools and to our equal payment plan.

Providing greater value to customers and shareholders was the principle behind our Conservation Tariff, which decouples the company's earnings and cash flow from the volume of gas it sends through the pipes. In August of 2005, the Public Utility Commission of Oregon, with the support of customer and environmental advocates, renewed the tariff for four more years and increased the coverage from 90 percent to 100 percent. The tariff applies to the Company's more than 550,000 Oregon customers. All parties agreed that the tariff benefits both customers and shareholders.

Our weather-normalization mechanism, called WARM, also added significant value to customers and shareholders in 2005. Customers saw less volatility in their wintertime bills and shareholders were protected from warmer-than-average weather. Together, WARM and the Conservation Tariff allow NW Natural to overcome two of the greatest challenges facing gas utilities today: earnings and cash flow uncertainty from fluctuating weather and declining per capita gas consumption. In 2005, the two mechanisms combined to add $1.6 million to margin.

NW Natural's efforts on behalf of its customers have made a difference. Last year the Company climbed to fifth place for overall customer satisfaction among gas utilities in a national J.D. Power's survey. In the western region, we ranked second.

Understanding the Challenge

In 2005, we benefited both from sound business strategies and a solid economic recovery. Population in Oregon grew by more than 46,000 in 2005, with two-thirds of that growth from residents moving here from other states. Unemployment is at its lowest level in almost five years. Housing starts remain strong and natural gas continues to be the fuel of choice for new construction. But as we recognize the elements that created a strong performance in 2005, we must also understand and plan for a future that includes the challenge of high natural gas prices.

High, more volatile gas prices will likely continue over the next several years as the nation works to tap new natural gas supplies. Passage of the 2005 Energy Policy Act is an important step in the right direction. Its provisions encourage greater exploration and production in the U.S. and attempt to improve the siting process for new Liquefied Natural Gas (LNG) import facilities. The ability to site new LNG terminals is a key issue in our service territory, where there are currently five project proposals being considered.

In addition to its focus on new supplies of natural gas and increased energy efficiency, the 2005 Energy Policy Act calls for a greater diversification of the sources of energy used to generate electricity. The heavy consumption of natural gas to run electric turbines contributes to rising gas prices and inefficient use of the fuel's energy content. With new supplies becoming available, greater energy efficiency and the more direct, efficient use of natural gas, analysts predict that prices will stabilize and even fall in the coming years.

However, in the meantime, we face the reality of high prices for the commodity we buy for our customers. NW Natural's goal is to make sure

Letter to shareholders

Dedicated to delivering value

To Our Shareholders:

NW Natural's most fundamental responsibility is to create value – for our shareholders, our customers, our employees and our communities. In 2005, the Company lived up to that responsibility, delivering a strong performance that paid healthy dividends, both literally and figuratively.

In a challenging period for the natural gas industry, we benefited by positioning the Company for higher profitability and fewer business risks. But it was not a year to rest. Building a strong platform for growth means always looking ahead of the next curve – anticipating challenges, looking for opportunities and creating strategies to capitalize on both.

NW Natural is proud of its financial results for 2005, but we are also more determined than ever to pursue initiatives that continue to foster the stability and growth that investors value.

Highlights of the Year

In 2005, NW Natural:

- Earned $2.11 a diluted share compared to $1.86 in 2004, up more than 13 percent;
- Marked 50 consecutive years of increasing dividends paid to shareholders;
- Secured regulatory renewal of our Conservation Tariff for another four years;
- Ranked fifth nationally and second in the West in J.D. Power's survey for customer satisfaction among the nation's 56 gas utilities;
- Continued expansion of our Mist gas storage facility to serve the interstate market;
- Refinanced a $200 million credit line at attractive rates;
- Managed our 19th consecutive year of customer growth of more than 3 percent;
- Grew to more than 617,000 customers; and
- Updated our Strategic Plan to refine and sharpen our strategic direction and focus on cost controls and operational excellence.

Strategies and Execution Deliver Value

Our performance last year demonstrated the value that can be produced by years of careful planning and disciplined execution. You can see it in our bottom line and in the many other achievements of 2005.

In addition to a 13 percent increase in earnings per share, last year the Company added its 600,000th customer, with the landmark customer coming in our newest service territory, Oregon's south coast. Customer growth exceeded 3 percent for the 19th consecutive year, remaining well above the national average of approximately 1.5 percent for natural gas distribution companies.

As our stock price increased in 2005, the Company's market capitalization hit $1 billion for the first time – putting NW Natural in the mid-cap stock range.

We also continued to expand our Mist underground gas storage capacity to take advantage of favorable conditions in the interstate storage market. The company's interstate storage business added 17 cents per share, an increase of 55 percent over 2004.

And in 2005 we marked 50 years of increasing dividends paid, an accomplishment shared by only three other companies in the U.S. In October, we celebrated this rare milestone by ringing the opening bell on the New York Stock Exchange.

As all of this suggests, 2005 was an exceptionally strong year for NW Natural, one that delivered greater value to its shareholders. And we believe customers benefited as well. The Company fought hard in the midst of soaring wholesale natural gas prices to provide its customers the greatest value possible. Compared to how gas customers fared in other parts of the country, we succeeded in a big way.

The Company's gas purchasing strategy, built around storage assets and disciplined hedging practices, helped our customers avoid most of the fallout following hurricanes Katrina and Rita. Even before the hurricanes hit, our regulators recognized NW Natural for keeping gas costs the lowest in the region. Many gas utilities across the nation passed on increases of 50 percent or more. We kept ours to approximately 15 percent in Oregon and 12 percent in Washington.

Creating value for shareholders

As a kid growing up in the Portland suburbs during the late 1970s, **Chris Bernard** always had an eye for value. He picked up returnable cans for the deposit. During the summer, he worked picking berries in the fields that once surrounded the metropolitan area.

"I made a little money at 13 or so, and my mom asked me what I was going to do with it,"says Bernard, now a 40-year-old Portland firefighter. "My uncle recommended utility stocks as safe and dividend paying."

So he took his crumpled bills and jar of coins to NW Natural's headquarters to buy some stock. "I had maybe $100 and I remember it was $9 a share," he says. From then on, he was hooked, reading the paper every day to check the progress on "his stock."

In 1987, he sold the stock to help pay for college. "That was hard to do personally, but I knew that's what it was for, so I did it."

He continued investing over the years, but always had a soft spot for NW Natural. When his son Benjamin turned 2, he took him downtown to buy some company shares. "The same lady was there as when I brought in my money as a kid and she remembered me. That was neat," he says. Last year, when his daughter Amelia turned one year old, they re-enacted the ritual. "It's great as we drive around I can point out a service truck and tell my kids that's their company," Bernard says.

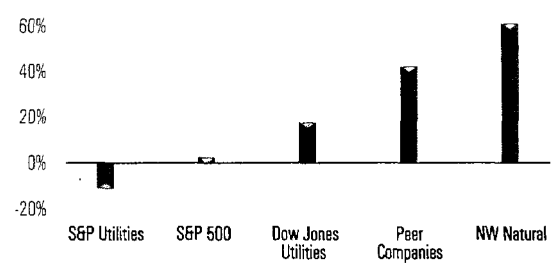
NW Natural is dedicated to creating shareholder value for individuals and generations of families such as the Bernards.

In 2005, the Company achieved 50 years of increasing dividends paid, a distinction shared by only three other companies in the U.S.

That's a story shareholders never tire of hearing.

Total Return Analysis

5 YEARS ENDED DECEMBER 31, 2005



Over the past five years, the Company's total shareholder return - made up of share price appreciation and reinvestment of dividends - shows that NW Natural returned nearly 61% to investors over the period, ahead of industry indices and peer companies.

- NW Natural - 60.91%
- Local gas distribution company peers - 43.51%
- Dow Jones Utilities index - 18.81%
- S&P 500 index - 2.80%
- S&P Utilities index - (10.89)%

Portland firefighter Chris Bernard has opened stock accounts for daughter Amelia, age 2, and son Benjamin, age 5. He took money from a paper route in the 1970s and invested in NW Natural stock. Now the stock is creating value for a new generation of Bernards.

Creating value for customers

For decades, Portland's south waterfront area lay barren and unsightly. A former riverfront industrial site just south of the city's vibrant downtown, the area is now the nation's largest urban renewal project. And NW Natural's innovative partnership with the developer is a critical part of the revitalization effort.

The River Blocks at South Waterfront will eventually host 10,000 jobs and 4,000 households – all in gas-supplied buildings spread over 128 acres. In the first phase, the development boasts four residential high rises and a 400,000 square-foot, 16-story medical research center for Oregon Health & Science University. The high-rise condos – between 21 and 31 stories – are under construction with over 90 percent already sold. With some creative design, NW Natural managed to serve each building with just one service line. Working with project architects, we were able to make dozens of cumbersome meter sets mesh seamlessly with the design of this high-profile project.

The result was less cost for the developer and the eventual residents. We added more customers in an efficient high-rise environment featuring gas appliances for heating water, water source heat pumps, cooking, fireplaces and barbeques – all with great views of Portland and the Willamette River. In the late 1990s, NW Natural made a strategic decision to pursue the multifamily market. As a result of the new programs that have been developed, the Company has been successful in growing our multifamily market share. This is particularly true for the owner-occupied, higher-end multifamily construction that has been a strong market in the Portland area for the last several years.

With projects like the River Blocks, NW Natural is creating value for customers and the entire metropolitan area.

With some creative design, NW Natural managed to serve each building with just one service line. Working with project architects, we were able to make dozens of cumbersome meter sets mesh seamlessly with the design of this high-profile project.

NW Natural's involvement in the River Blocks project south of downtown Portland is part of a strategy to target new multifamily developments in the Company's service territory.

NW Natural is gaining market share of newly built condos and apartments in the Portland market.

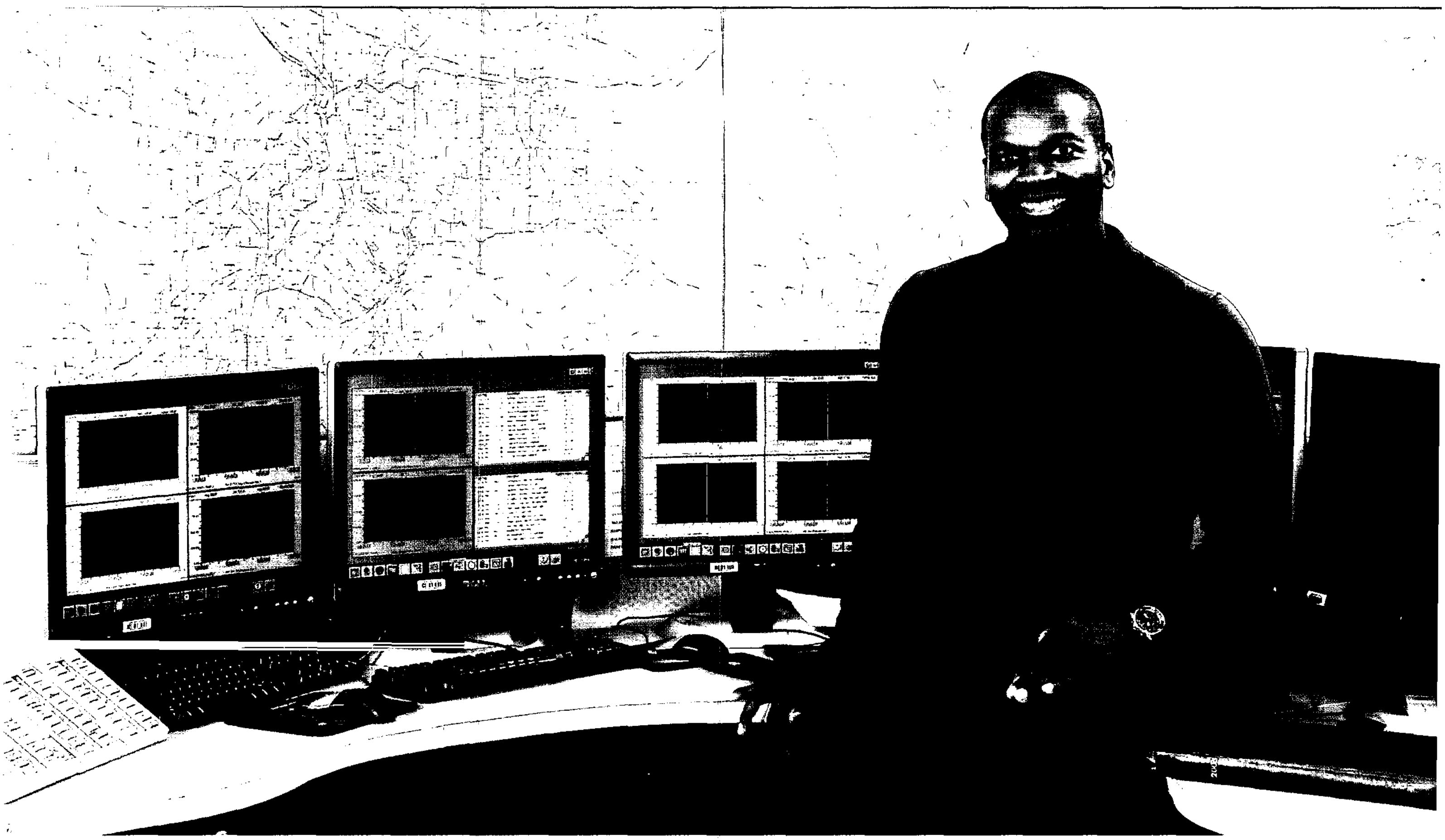
Creating value for employees

Last year, NW Natural signed up its 600,000th customer, double the number that we served in 1989; yet the Company actually reached that milestone with fewer employees than it had 16 years ago.

NW Natural employees are adding more value than ever, and in today's constantly changing environment, intensified competition demands their adaptability, creativity and constant vigilance for better, more efficient ways to do the work.

As employees add value to the Company, NW Natural in turn invests in its employees. Providing competitive wages and benefits and a sound retirement plan are a few of the tangible ways. Others are investing in employee development and providing opportunities for career growth and personal achievement. NW Natural is a place where employees can aim for these goals and, with hard work, realize them.

Eugene Clark started with NW Natural in 1991 as a distribution helper, working on a field crew. "I asked a lot of questions, so eventually they put me in the answer department," he says now. After advancing to pipe joiner, he moved indoors as a gas controller in



1996. He serves as a traffic controller for company gas supplies as they move through the territory.

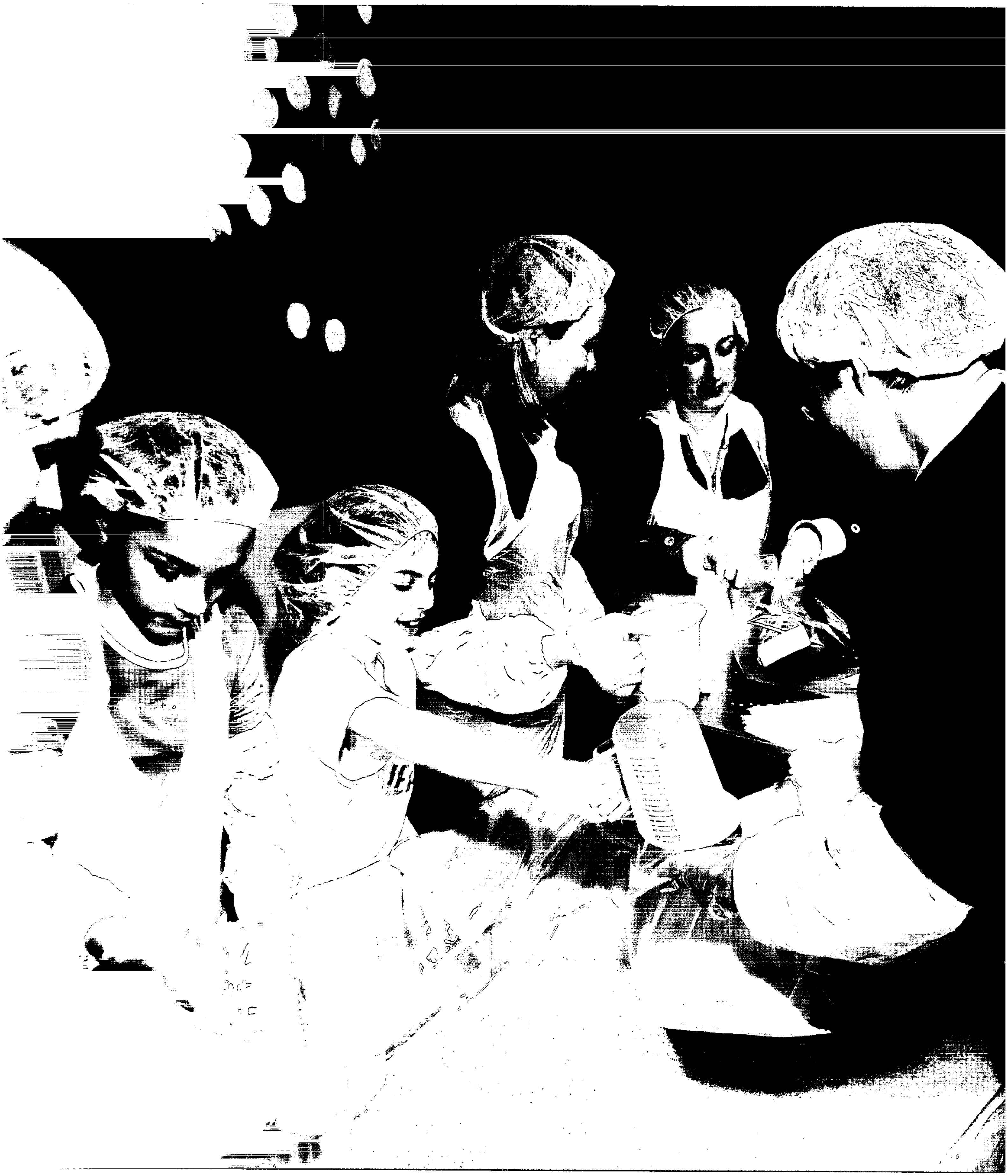
"At heart, I'm an analyst. I like solving problems and here I get to work on a team that manages change on a daily basis," Clark says.

Keeping ahead of technology has been **Lori Russell's** mantra at NW Natural since she joined the Company as a clerk in 1980. In those days before voicemail or e-mail, she answered the phone and took messages for 45 people. Managers kept budgets using pencils on huge spreadsheets. Over the years, she grew with the Company, working as a supervisor in Customer Equipment Services, a claims agent in Land & Risk and then into Construction Management. Russell now serves as general manager of gas operations with responsibility for more than 70 employees who build and maintain our distribution system. With her broad experience throughout the Company, Russell specializes in heading cross-functional teams dedicated to operational efficiency.

"Every place I've gone in the Company, I've taken my desire to automate with me," she says.

Above, Eugene Clark joined NW Natural as a helper on field crews and now is a gas controller. "I asked a lot of questions, so eventually they put me in the answer department," he says.

Left, Lori Russell, general manager of gas operations, confers on how to make a project more cost effective with (left to right) Richard Brown, construction estimator; Yogi Rattay, construction field supervisor; Tim Callahan, field operations coordinator; and Jerry Hulett, field engineering technician.



Creating value for communities

A business can't succeed for long if it doesn't exist in a healthy and vital community. NW Natural understands this relationship - and has from the very start. We have a 147-year legacy of involvement in the communities we serve. The Company and its employees actively participate and support local causes with contributions of time and dollars, adding value in many ways.

In 2005, 304 organizations or projects received funding through NW Natural's philanthropy programs. The Company gave more than $60,000 to Oregon Food Bank, our signature program, and our employees contributed an additional $7,226 to the food drive. Employees also extended a helping hand to the victims of hurricanes Katrina and Rita, helping to raise nearly $100,000 on their way to setting a new record for the annual employee charitable giving campaign.

We also reached out to smaller charitable groups. Last year, we awarded $15,500 to more than 43 employees who had applied for small grants to support their community efforts. The projects ranged from homework clubs at inner city schools to rehabilitating area streams to supporting the families of soldiers serving overseas. In itself, each grant may have been small, but together the resources help to improve the communities we serve.

The Company also supports the community-building efforts of our employees and management. We look for opportunities to support the creative, dedicated instincts of our people that come naturally when individuals become involved in communities where they live and work.

We encourage employees to donate their time to useful efforts such as repackaging food at their local food banks. Others packaged and delivered backpacks filled with school supplies from the Tools for Schools program to children in disadvantaged neighborhoods of Portland. In a new initiative, NW Natural employees apply for a special sabbatical to take a few months to use their skills to help kick start an important nonprofit program of their choice.

In all, we contributed $822,320 to charitable organizations that make a difference in the lives of people in our service territory.

For NW Natural, contributing to our communities isn't just good business – it's a core value.

A business can't succeed for long if it doesn't exist in a healthy and vital community. NW Natural understands this relationship – and has from the very start.

NW Natural employees and their families lend a hand packing food boxes for families in need. Maheyla Molinari, daughter of DeeAnna Molinari of human resources, Melissa Rosenberry, [illegible] administrator, and Denise Stinson, wife of employee Charlie Stinson, all spent a Saturday morning making sure other families had something in the cupboard.

Company Overview

Corporate Profile

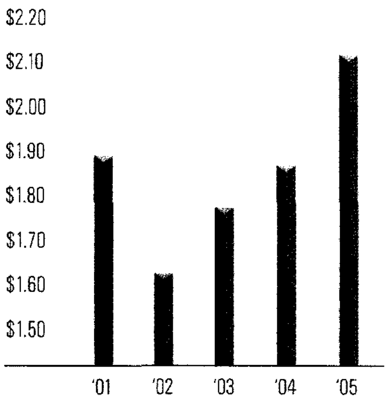
NW Natural is a 147-year-old natural gas local distribution company headquartered in Portland, Oregon. The Company has added customers at a rate of 3 percent or more per year for 19 consecutive years. NW Natural serves more than 617,000 customers in Oregon and southwest Washington, including the Portland-Vancouver metropolitan area, the Willamette Valley, the Oregon coast and the Columbia River Gorge. More than 200,000 customers have been added to NW Natural's distribution system in the past 10 years. In keeping with its steady growth, the Company has increased annual dividends paid to shareholders every year for 50 consecutive years. NW Natural purchases natural gas for its core market from a variety of suppliers in the western United States and Canada. The Company also operates an underground gas storage facility and contracts for additional gas storage outside its service area. NW Natural operates two liquefied natural gas plants in its service area. The Company also provides interstate gas storage services to other energy companies in the Northwest interstate market, using capacity that has been developed in advance of its core customers' needs.

Financial and Operating Highlights

	2005	2004	Percent increase (decrease)
Earnings			
Financial facts ($000):			
Net operating revenues	324,993	291,495	11
Net income	58,149	50,572	15
Financial ratios (%):			
Return on average common equity	10.1	9.4	7
Capital structure at year-end:			
Long-term debt	47.0	46.0	2
Common stock equity	53.0	54.0	(2)
Common stock			
Shareholder data:			
Common shareholders	9,136	9,359	(2)
Average shares outstanding (000)	27,564	27,016	2
Per share data ($):			
Basic earnings	2.11	1.87	13
Diluted earnings	2.11	1.86	13
Dividends paid on common stock	1.32	1.30	2
Book value at year-end	21.28	20.64	3
Market value at year-end	34.18	33.74	1
Operating highlights			
Gas sales and transportation deliveries (000 therms)	1,157,567	1,131,866	2
Degree days (25-year average, 4,265)	4,178	3,853	8
Customers at year-end	617,163	596,635	3
Number of utility employees	1,305	1,288	1
Dividends paid on common stock (per share)			
Payment date			
February 15	$ 0.325	$ 0.325	
May 15	$ 0.325	$ 0.325	
August 15	$ 0.325	$ 0.325	
November 15	$ 0.345	$ 0.325	
Total dividends paid	$ 1.320	$ 1.300	

Earnings Per Share

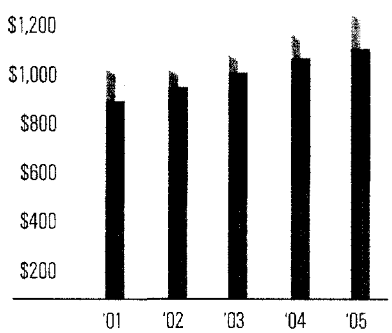
IN DOLLARS



Diluted earnings were $2.11 per share in 2005, up 13 percent over 2004. Diluted earnings per share in 2002 include a charge of $0.33 per share related to a terminated acquisition.

Capitalization

IN MILLIONS OF DOLLARS

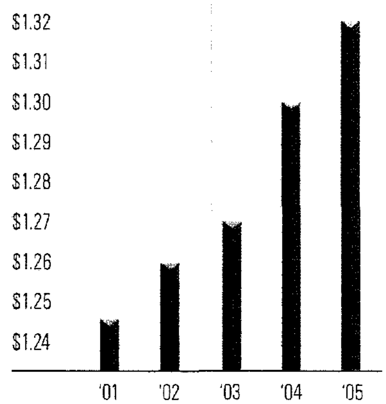


- COMMON EQUITY
- PREFERRED AND PREFERENCE STOCK
- LONG-TERM DEBT
- SHORT-TERM DEBT

In 2005, $15 million in long-term debt was retired, and $50 million in long-term debt was issued.

Dividends Paid Per Share

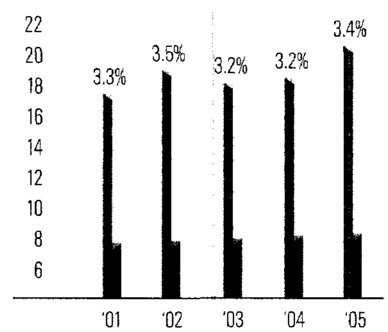
IN DOLLARS



Annual dividends paid per share in 2005 increased for the 50th consecutive year, a growth record matched by few companies. The indicated dividend rate at year-end 2005 was $1.38 per share.

Customer Growth & Annual Growth Rate

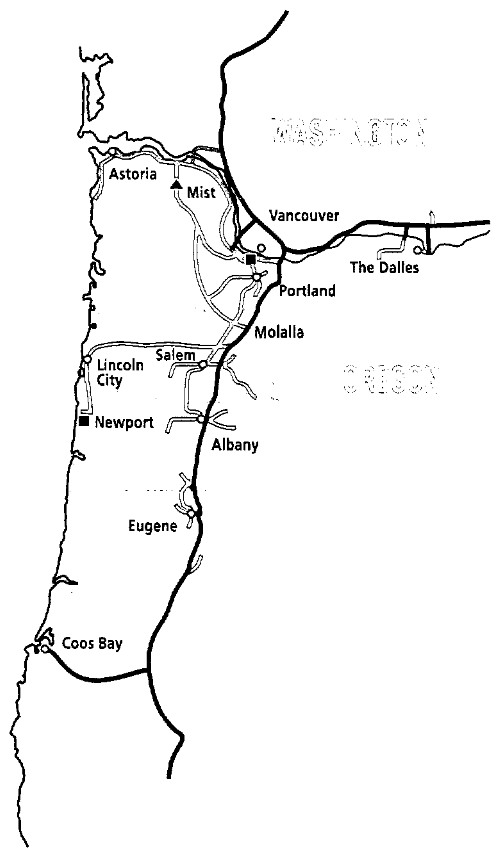
IN THOUSANDS



- NW NATURAL
- NATIONAL AVERAGE

NW Natural has consistently added new customers and grown at a rate of more than twice the national average for the past 19 years, including 2005 when the Company's annual growth rate was 3.4 percent, compared to the national gas distribution industry average of approximately 1.5 percent annually.

Service Territory



Legend

- Williams Gas Pipeline
- NW Natural gas transmission line
- Kelso Beaver (KB) Pipeline
- Coos County Pipeline
- ■ LNG plant
- ○ District offices
- ▲ Mist underground storage

Comparative Condensed Consolidated Income Statements

Thousands, except per share amounts (year ended December 31)	**2005**	**2004**	**2003**	**2002****	**2001**
Operating revenues:					
Gross operating revenues	$ 910,486	$ 707,604	$ 611,256	$ 641,376	$ 650,252
Cost of sales	563,860	399,244	323,190	353,832	374,241
Revenue taxes *	21,633	16,865	14,650	14,743	14,645
Net operating revenues	324,993	291,495	273,416	272,801	261,366
Operating expenses:					
Operations and maintenance	113,216	102,155	96,420	85,120	83,920
General taxes *	23,185	21,943	20,475	19,333	17,595
Depreciation and amortization	61,645	57,371	54,249	52,090	49,640
Total operating expenses	198,046	181,469	171,144	156,543	151,155
Income from operations	126,947	110,026	102,272	116,258	110,211
Other income and expense – net	1,205	2,828	2,150	(14,890)	1,334
Interest charges – net of amounts capitalized	37,283	35,751	35,099	34,132	33,805
Income before income taxes	90,869	77,103	69,323	67,236	77,740
Income tax expense	32,720	26,531	23,340	23,444	27,553
Net income	58,149	50,572	45,983	43,792	50,187
Redeemable preferred and preference stock dividend requirements	-	-	294	2,280	2,401
Earnings applicable to common stock	$ 58,149	$ 50,572	$ 45,689	$ 41,512	$ 47,786
Average common shares outstanding:					
Basic	27,564	27,016	25,741	25,431	25,159
Diluted	27,621	27,283	26,061	25,814	25,612
Earnings per share of common stock:					
Basic	$ 2.11	$ 1.87	$ 1.77	$ 1.63	$ 1.90
Diluted	$ 2.11	$ 1.86	$ 1.76	$ 1.62	$ 1.88
Dividends paid per share of common stock	$ 1.32	$ 1.30	$ 1.27	$ 1.26	$ 1.245

See Notes to Consolidated Financial Statements in the Company's Annual Report on Form 10-K.

* Revenue taxes were reclassified from general taxes.

** Includes a loss of $13.9 million in 2002 for charges related to a terminated acquisition.

Comparative Condensed Consolidated Balance Sheets

Thousands of dollars (December 31)	2005	2004	2003	2002	2001
Assets:					
Plant and property:					
Utility plant	$ 1,875,444	$ 1,794,972	$ 1,657,589	$ 1,539,965	$ 1,465,079
Less accumulated depreciation	536,867	505,286	471,716	435,601	398,668
Utility plant - net	1,338,577	1,289,686	1,185,873	1,104,364	1,066,411
Non-utility property	40,836	33,963	23,395	20,832	18,203
Less accumulated depreciation and amortization	5,990	5,244	4,855	4,404	4,007
Non-utility property - net	34,846	28,719	18,540	16,428	14,196
Total plant and property	1,373,423	1,318,405	1,204,413	1,120,792	1,080,607
Other investments	58,451	60,618	73,845	67,619	76,266
Current assets:					
Cash and cash equivalents	7,143	5,248	4,706	7,328	10,440
Accounts receivable	84,418	60,634	48,369	48,751	66,684
Accrued unbilled revenue	81,512	64,401	59,109	44,069	57,749
Allowance for uncollectible accounts	(3,067)	(2,434)	(1,763)	(1,815)	(1,962)
Inventories of gas, materials and supplies	86,161	66,477	50,859	58,030	49,337
Prepayments and other current assets	67,543	42,791	34,554	36,934	28,086
Total current assets	323,710	237,117	195,834	193,297	210,334
Regulatory assets	98,578	91,263	77,272	61,523	172,382
Fair value of non-trading derivatives	178,653	16,399	23,885	12,426	-
Other assets	9,216	8,393	10,130	11,620	11,064
Total assets	$ 2,042,031	$ 1,732,195	$ 1,585,379	$ 1,467,277	$ 1,550,653
Capitalization and liabilities:					
Capitalization:					
Common stock equity	$ 586,931	$ 568,517	$ 506,316	$ 482,392	$ 468,161
Redeemable preference stock	-	-	-	-	25,000
Redeemable preferred stock	-	-	-	8,250	9,000
Total capital stock	586,931	568,517	506,316	490,642	502,161
First mortgage bonds	521,500	479,500	494,500	439,500	370,000
Unsecured debt	-	4,527	5,819	6,445	8,377
Total long-term debt	521,500	484,027	500,319	445,945	378,377
Total capitalization	1,108,431	1,052,544	1,006,635	936,587	880,538
Current liabilities:					
Notes payable	126,700	102,500	85,200	69,802	108,291
Accounts payable	135,287	102,478	86,029	74,436	70,698
Long-term debt due within one year	8,000	15,000	-	20,000	40,000
Taxes accrued	12,725	10,242	8,605	7,822	22,539
Interest accrued	2,918	2,897	2,998	2,902	3,658
Other current and accrued liabilities	40,935	34,168	31,589	30,045	28,396
Total current liabilities	326,565	267,285	214,421	205,007	273,582
Regulatory liabilities	344,212	165,699	166,714	150,049	127,705
Deferred investment tax credits	5,069	5,660	6,945	7,824	8,682
Deferred income taxes	222,331	211,080	171,797	141,732	130,424
Fair value of non-trading derivatives	6,876	5,487	-	-	111,868
Other liabilities	28,547	24,440	18,867	26,078	17,854
Total capitalization and liabilities	$ 2,042,031	$ 1,732,195	$ 1,585,379	$ 1,467,277	$ 1,550,653

See Notes to Consolidated Financial Statements in the Company's Annual Report on Form 10-K.

Certain amounts from prior years have been reclassified to conform with the current financial statement presentation.

Comparative Financial Statistics

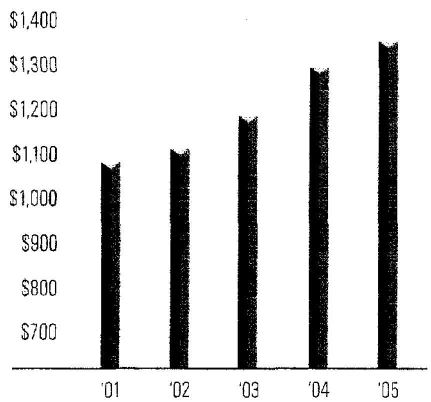
	2005	2004	2003	2002*	2001
Common stock					
Ratios at year-end:					
Price/earnings ratio	16.2	18.0	17.3	16.6	13.4
Dividend yield at year-end rate - %	4.0	3.9	4.1	4.7	4.9
Dividend payout - %	62.6	69.5	71.8	77.3	65.5
Return on average common equity - %	10.1	9.4	9.3	8.7	10.4
Per share data – ($):					
Basic earnings	2.11	1.87	1.77	1.63	1.90
Diluted earnings	2.11	1.86	1.76	1.62	1.88
Dividends paid	1.32	1.30	1.27	1.26	1.245
Indicated dividend rate at year-end	1.38	1.30	1.30	1.26	1.26
Book value at year-end	21.28	20.64	19.52	18.85	18.56
Market price:					
High	39.63	34.13	31.30	30.70	26.69
Low	32.42	27.46	24.05	23.46	21.65
Year-end	34.18	33.74	30.75	27.06	25.50
Average	35.92	31.06	27.72	27.58	23.67
Number of shares of common stock outstanding (000):					
Year-end	27,579	27,547	25,938	25,586	25,228
Average	27,564	27,016	25,741	25,431	25,159
Coverage data – times earned					
Fixed charges - Securities and Exchange Commission	3.32	3.02	2.84	2.85	3.14
Utility plant					
Capital expenditures (000)	$ 89,259	$ 138,347	$ 121,411	$ 78,156	$ 72,235
Depreciation - % of average depreciable utility plant	3.4	3.4	3.5	3.5	3.5
Accumulated depreciation - % of depreciable utility plant	38.4	37.2	38.0	37.3	35.8
Capital structure at year-end (%)					
(Exclusive of current portion of long-term debt)					
First mortgage bonds	47.0	45.6	49.0	46.9	42.0
Unsecured debt	-	0.4	0.7	0.7	1.0
Total long-term debt	47.0	46.0	49.7	47.6	43.0
Redeemable preferred stock	-	-	-	0.9	1.0
Redeemable preference stock	-	-	-	-	2.8
Common stock equity	53.0	54.0	50.3	51.5	53.2
Total capital stock	53.0	54.0	50.3	52.4	57.0
Total capital structure	100.0	100.0	100.0	100.0	100.0
Effective tax rate					
Effective tax rate - % of pretax income	36%	34%	34%	35%	35%

*Includes impact from a charge of $0.33 per share in 2002 related to a terminated acquisition.

Comparative Operating Statistics

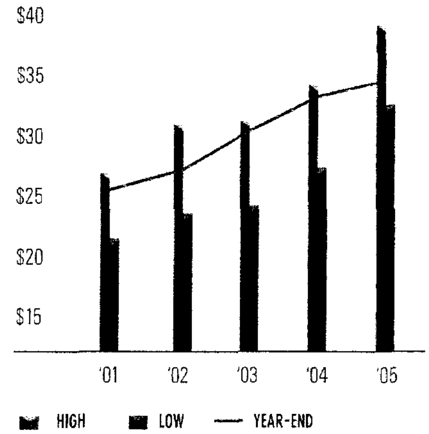
Selected Utility Data	**2005**	**2004**	**2003**	**2002**	**2001**
Customers at year-end					
Residential	556,667	537,152	519,427	503,402	485,207
Commercial	59,543	58,548	57,969	56,087	55,096
Industrial firm	667	658	478	306	383
Industrial interruptible	214	193	165	31	148
Total sales customers	617,091	596,551	578,039	559,826	540,834
Transportation customers	72	84	111	241	97
Total customers	617,163	596,635	578,150	560,067	540,931
Gas sales and transportation deliveries (000 therms)					
Residential	366,990	356,199	343,534	357,091	350,065
Commercial	231,896	226,490	226,257	240,155	242,293
Industrial firm	74,963	63,149	55,314	63,215	79,778
Industrial interruptible	149,106	104,278	47,994	26,241	63,597
Total gas sales	822,955	750,116	673,099	686,702	735,733
Transportation	328,056	389,514	414,554	445,999	385,783
Unbilled therms	6,556	(7,764)	12,099	(6,617)	1,771
Total volumes delivered	1,157,567	1,131,866	1,099,752	1,126,084	1,123,287
Operating revenues and cost of sales (000)					
Utility operating revenues:					
Residential	$ 460,204	$ 380,832	$ 328,346	$ 354,735	$ 329,905
Commercial	244,824	199,444	176,336	201,475	190,236
Industrial firm	64,247	44,625	33,578	42,965	49,662
Industrial interruptible	100,740	55,380	23,661	15,937	34,283
Total gas sales revenues	870,015	680,281	561,921	615,112	604,086
Transportation	10,755	12,655	17,962	26,020	20,637
Unbilled revenues	17,021	3,849	14,474	(12,702)	13,774
Other	2,862	4,160	7,627	4,018	(2,325)
Total utility operating revenues	900,653	700,945	601,984	632,448	636,172
Cost of gas sold	563,772	399,176	323,128	353,034	364,699
Revenue taxes	21,633	16,865	14,650	14,743	14,645
Utility net operating revenues	$ 315,248	$ 284,904	$ 264,206	$ 264,671	$ 256,828
Customer data					
Heat requirements:					
Actual degree days	4,178	3,853	3,952	4,232	4,325
Percent colder (warmer) than average	(2%)	(10%)	(7%)	(1%)	1%
Average use per customer in therms:					
Residential	673	677	673	725	738
Commercial	3,936	3,907	4,004	4,334	4,435
Average sales rate per therm (cents):					
Residential	125.2	107.1	95.6	99.3	94.2
Commercial	105.4	88.2	78.0	83.9	78.5
Industrial firm	85.7	70.7	60.7	68.0	62.2
Industrial interruptible	67.6	53.1	49.3	61.7	54.0
Total sales	105.6	90.8	83.5	89.6	82.1
Gas purchases (000 therms)	815,334	756,672	683,331	708,796	739,620
Gas purchased cost per therm – net (cents)	71.42	56.60	46.99	51.07	47.19
Average sendout cost of gas (cents)	67.96	53.77	47.16	51.91	49.45
Maximum day firm sendout (000 therms)	5,649	7,177	4,851	4,249	4,247
Maximum day total sendout (000 therms)	6,966	8,913	6,310	6,172	5,996
Utility employees	1,305	1,288	1,291	1,261	1,284
Number of customers served by each operating employee	738	721	724	714	671

Net Utility Plant
IN MILLIONS OF DOLLARS



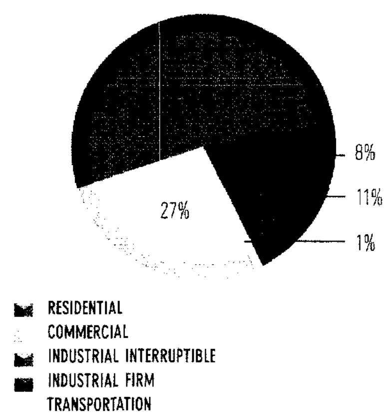
Utility plant continued to increase in 2005 as a result of customer growth and investments in infrastructure and utility gas storage.

High/Low Market Price Per Share
IN DOLLARS



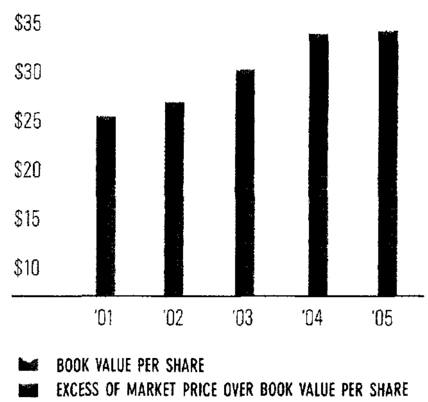
Price per share at year end increased 34 percent in five years.

2005 Utility Gas Revenues
BY CUSTOMER CLASS



Revenues from residential, commercial and industrial firm sales customers have consistently exceeded 87 percent of total gas revenues since 1995.

Year-End Market Price & Book Value Per Share
IN DOLLARS



The year-end market-to-book ratio averaged 1.52x over the past five years. Total return to shareholders from dividends paid and stock appreciation was about 10 percent for this period.

NW Natural®
220 N.W. Second Avenue
Portland, Oregon 97209
(503) 226-4211 • (800) 422-4012
nwnatural.com

Stock Transfer Agent and Registrar
For the Common Stock:
American Stock Transfer & Trust Company
59 Maiden Lane, Plaza Level
New York, New York 10038
Telephone: (888) 777-0321
Internet: amstock.com
E-mail: info@amstock.com

Trustee and Bond Paying Agent
For all bond issues:
Deutsche Bank Trust Company Americas
60 Wall Street
27th Floor - MS NYC60-2710
New York, NY 10005
Telephone: (800) 735-7777

Quarterly Financial Information (unaudited)

Dollars *(thousands except per share amounts)*	Quarter ended March 31	June 30	Sept. 30	Dec. 31	Total
2005					
Operating revenues	$ 308,777	$ 153,667	$ 106,667	$ 341,375	$ 910,486
Net operating revenues**	120,986	57,649	41,940	104,418	324,993
Net income (loss)	39,887	1,140	(8,671)	25,793	58,149
Basic earnings (loss) per share	1.45	0.04	(0.31)	0.94	2.11*
Diluted earnings (loss) per share	1.43	0.04	(0.31)	0.93	2.11*
2004					
Operating revenues	$ 254,450	$ 109,659	$ 81,441	$ 262,054	$ 707,604
Net operating revenues**	105,927	50,043	37,466	98,059	291,495
Net income (loss)	32,612	(716)	(8,285)	26,961	50,572
Basic earnings (loss) per share	1.26	(0.03)	(0.30)	0.98	1.87*
Diluted earnings (loss) per share	1.24	(0.03)	(0.30)	0.97	1.86*

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

** As of December 31, 2005, revenue taxes are included in net operating revenues. Revenue taxes are expenses primarily related to utility franchise agreements and are based on gross operating revenues. Since revenue taxes are a direct cost of utility sales, these expenses were reclassified to net operating revenues. Prior periods' quarterly and annual amounts have been reclassified to conform with the current presentation, and these reclassifications did not have an impact on net income (loss).

Common Stock Prices

NW Natural's common stock is listed and trades on the New York Stock Exchange under the symbol "NWN." The quarterly high and low trades for NW Natural's common stock during the past two years were as follows:

2005 Quarter Ended	High	Low
March 31	$ 37.24	$ 32.42
June 30	38.67	34.36
September 30	39.63	35.60
December 31	37.77	33.25

2004 Quarter Ended	High	Low
March 31	$ 33.00	$ 29.95
June 30	31.65	27.46
September 30	32.37	28.84
December 31	34.13	30.77

The closing quotations for the common stock on December 30, 2005 and December 31, 2004 were $34.18 and $33.74, respectively.

Notice of Annual Meeting

The 2006 Annual Meeting will be held at 2 p.m., Thursday, May 25, in the Colonel Lindbergh Room of the Embassy Suites Hotel, 319 S.W. Pine Street, Portland, Oregon. A meeting notice and proxy statement will be sent to all shareholders in mid-April.

Dividend Reinvestment and Direct Stock Purchase Plan

Participants may make an initial investment in Company stock and common shareholders of record may reinvest all or part of their dividends in additional shares under the Company's plan. Cash purchases may also be made. Participants in the Plan bear the cost of brokerage fees and commissions for shares purchased on the open market to fulfill purchases under the Plan. A prospectus will be sent upon request.

Dividend Payment Dates

February 15, 2006
May 15, 2006
August 15, 2006
November 15, 2006

Certifications

The Chief Executive Officer certified to the NYSE on June 6, 2005 that, as of that date, he was not aware of any violation by the Company of NYSE's corporate governance listing standards, and the Company has filed with the Securities and Exchange Commission, as exhibits 31.1 and 31.2 to its Annual Report on Form 10-K for the year ended December 31, 2005, the certificates of the Chief Executive Officer and the Chief Financial Officer of the Company certifying the quality of the Company's public disclosure.

Contact the NW Natural Board

Concerns may be directed to the non-management directors as follows:

- Call 800-541-9967, or
- Write to NW Natural Board of Directors, c/o Corporate Secretary, or
- E-mail Directors@nwnatural.com

Forward-looking Statements

NW Natural's future operating results will be affected by various uncertainties and risk factors, many of which are beyond the Company's control, including governmental policy and regulatory action, the competitive environment, economic factors and weather conditions. Some statements in this annual report may be forward-looking, and actual results may differ materially as a result of these uncertainties. For a more complete description of these uncertainties and risk factors, please refer to the Company's filings with the Securities and Exchange Commission on Forms 10-K and 10-Q.

Shareholder Information

Robert S. Hess
Investor Relations
(503) 220-2388
(800) 422-4012
Ext. 2388
rsh@nwnatural.com

Carol M. Frary
Shareholder Services
(503) 220-2590
(800) 422-4012
Ext. 3412
cmf@nwnatural.com

Request for Publications

The following publications may be obtained without charge by contacting the Corporate Secretary:

Annual Report; Form 10-K; Form 10-Q; Corporate Governance Standards; Director Independence Standards; Code of Ethics; and Board Committee Charters.

These publications, as well as other filings made with the Securities and Exchange Commission, also are available on NW Natural's Web site at nwnatural.com.

Board of Directors

Standing (left to right) Kenneth Thrasher, Martha (Stormy) Byorum, John Carter, Russell Tromley, Scott Gibson, Randall Papé, Richard Woolworth
Seated (left to right) Timothy Boyle, Tod Hamachek, Richard Reiten, Mark Dodson

TIMOTHY BOYLE

Timothy P. Boyle, 56, is President and Chief Executive Officer of Columbia Sportswear Company located in Portland, Oregon. He was elected to the NW Natural Board of Directors in 2003, and serves on the Finance Committee, Strategic Planning Committee, and Organization and Executive Compensation Committee.

MARTHA (STORMY) BYORUM

Ms. Byorum, 57, is Senior Managing Director, Stephens Cori Capital Advisors, a private equity advisory and investment banking firm located in New York City. She was elected to the Board in 2004 and serves as a member of the Finance Committee and Audit Committee.

JOHN CARTER

A member of the NW Natural Board since 2002, John D. Carter, 60, chairs the Board's Audit Committee. He is also a member of the Governance and Finance Committees. Mr. Carter is President and Chief Executive Officer of Schnitzer Steel Industries, Inc., in Portland, Oregon.

MARK DODSON

NW Natural's President and Chief Executive Officer is Mark S. Dodson, 61. Previously he served as NW Natural's General Counsel and Senior Vice President, Public Affairs. He has served on the Board since 2003.

SCOTT GIBSON

C. Scott Gibson, 53, is President of Gibson Enterprises, a company that manages private investments in Portland, Oregon. Mr. Gibson joined the NW Natural Board in 2002. He is Chair of the Public Affairs and Environmental Policy Committee and a member of the Strategic Planning Committee and the Organization and Executive Compensation Committee.

TOD HAMACHEK

Chair of the Strategic Planning Committee, Tod R. Hamachek, 60, has served on the NW Natural Board since 1986. Mr. Hamachek is also a member of the Board's Audit and Governance Committees. Until February 2005, he served as Chairman and Chief Executive Officer of Penwest Pharmaceuticals Company, a firm that develops pharmaceutical drug delivery products and technologies in Danbury, Connecticut.

RANDALL PAPÉ

A member of the Board since 1996, Randall C. Papé, 55, chairs the Finance Committee. Mr. Papé is President and Chief Executive Officer of The Papé Group, Inc., headquartered in Eugene, Oregon, which specializes in the sales and service of capital equipment. He serves on the Board's Governance Committee and its Public Affairs and Environmental Policy Committee.

RICHARD REITEN

Retired Chairman of the Board, Richard G. Reiten, 66, has been a member of the Board since 1996. Mr. Reiten retired as President and Chief Executive Officer of NW Natural in 2002. He also served as President and Chief Operating Officer of Portland General Electric from 1992-1995. Mr. Reiten serves on the Finance Committee, the Public Affairs and Environmental Policy Committee and the Strategic Planning Committee.

KENNETH THRASHER

Elected to the Board of Directors in February 2005, Kenneth Thrasher, 56, is Chairman and Chief Executive Officer of Compli Corporation, a software solution provider for corporate compliance management in employment practices and governance. Mr. Thrasher served as an executive for 19 years with Fred Meyer, Inc., including President and Chief Executive Officer from 1999-2001.

RUSSELL TROMLEY

The Chair of the Organization and Executive Compensation Committee is Russell F. Tromley, 66. He has served on the Board since 1994, and is a member of the Audit and Governance Committees. Mr. Tromley is Chairman and Chief Executive Officer of Tromley Industrial Holdings, Inc., a company in Tualatin, Oregon, that manufactures foundry equipment and distributes nonferrous metals.

RICHARD WOOLWORTH

Elected to the Board in 2000, Richard L. Woolworth, 64, chairs the Governance Committee, and was selected to serve as Chair of the Board effective March 1, 2005. He also serves on the Audit Committee. Mr. Woolworth is the Retired Chairman and Chief Executive Officer of The Regence Group, a regional affiliation of health plans in Portland, Oregon.

Corporate Officers

David H. Anderson, 44 [2004]
Senior Vice President and Chief Financial Officer (2004-present)
Senior VP and CFO, TXU Gas (2004)
Corporate Controller and Principal Accounting Officer, TXU Corp. (2003-2004)
VP, Investor Relations and Shareholder Services, TXU Corp. (1997-2003)

Mark S. Dodson, 61 [1997]
President and Chief Executive Officer (2003-present)
President and Chief Operating Officer (2001-2002)
General Counsel (1997-2002)
Senior Vice President, Public Affairs (1997-2001)

Lea Anne Doolittle, 51 [2000]
Vice President, Human Resources (2000-present)
Director of Compensation, PacifiCorp (1993-2000)

Stephen P. Feltz, 50 [1982]
Treasurer and Controller (1999-present)
Assistant Treasurer and Manager, General Accounting (1996-1999)

Margaret D. Kirkpatrick, 51 [2005]
Vice President and General Counsel (2005-present)
Partner, Stoel Rives LLP (1990-2005)

Gregg S. Kantor, 48 [1996]
Senior Vice President, Public and Regulatory Affairs (2003-present)
Vice President, Public Affairs and Communications (1998-2002)

Richelle T. Luther, 37 [2002]
Assistant Secretary (2002-present)
Associate, Stoel Rives LLP (1997-2002)

Michael S. McCoy, 62 [1969]
Executive Vice President, Customer and Utility Operations (2000-present)
Senior Vice President, Customer and Utility Operations (1999-2000)

C. J. Rue, 60 [1974]
Secretary (1982-present)
Assistant Treasurer (1987-present)

[Date joined NW Natural]

Form 10-K Annual Report

SECURITIES AND EXCHANGE COMMISSION
Washington, D. C. 20549

FORM 10-K

(Check 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, 2005

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

NW Natural

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, $3 1/6 par value, and Common Share Purchase Rights	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 Exchange Act. [ ]

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act:
Large accelerated filer [X] Accelerated filer [ ] Non-accelerated filer [ ]

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

As of June 30, 2005, the registrant had 27,553,685 shares of its Common Stock, $3 1/6 par value, outstanding. The aggregate market value of these shares of Common Stock (based upon the closing price of these shares on the New York Stock Exchange on that date) held by non-affiliates was $1,044,468,263.

Indicate number of shares outstanding of each of registrant's classes of common stock as of February 23, 2006:
Common Stock, $3 1/6 par value, and Common Share Purchase Rights 27,582,296

DOCUMENTS INCORPORATED BY REFERENCE

List documents incorporated by reference and the Part of the Form 10-K into which the document is incorporated. Portions of the Proxy Statement of Company, to be filed in connection with the 2006 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, 2005

Table of Contents

GLOSSARY OF TERMS

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

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

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

Bypass: a direct connection to the interstate gas pipeline, which circumvents the pipes of the local distribution company; usually considered only by large industrial users.

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

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

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

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

Design day: a design day is the maximum anticipated demand on the natural gas distribution system during a 24-hour period assuming weather at an average temperature of 12° F, the coldest day in the last 20 years in our service territory.

Diluted earnings per share: earnings applicable to common stock for a period, divided by the average number of shares of stock that would be outstanding if all securities convertible into common stock were converted and all options to purchase common stock with exercise prices lower than the average price for the period were exercised.

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.

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

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

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

Liquefied natural gas (LNG): the cryogenic liquid form of natural gas. At temperatures below minus 258 degrees Fahrenheit, natural gas can be stored in a liquid form, which is 600 times more dense than its gaseous form.

Margin: gross operating revenues, less cost of sales. Also referred to as net operating revenues.

Purchased Gas Adjustment (PGA): also known as the gas tracker, is a regulatory mechanism for adjusting customer rates due to changes in gas costs.

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

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

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

Underground gas storage: storage of natural gas by injection into underground rock formations for withdrawal during the winter heating season, such as at our Mist storage field.

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

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

Winter heating season: generally considered to be the period from November through March.

NORTHWEST NATURAL GAS COMPANY
PART I

ITEM 1. BUSINESS

General

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

Business Segments

Local Gas Distribution

We are principally engaged in the distribution of natural gas in Oregon and southwest Washington. In this report our principal business segment is referred to as local gas distribution or utility. Local gas distribution involves purchasing gas from producers, transporting the gas over interstate pipelines from the supply basins to our service territory, and reselling the gas to customers at rates and terms approved by the Oregon Public Utility Commission (OPUC) or by the Washington Utilities and Transportation Commission (WUTC). Gas distribution also includes transporting gas owned by large customers from the interstate pipeline connection, or city gate, to the customers' facilities for a fee, also approved by the OPUC or WUTC. Approximately 98 percent of our consolidated assets are related to the local gas distribution segment. The OPUC has allocated to us as our exclusive service area a major portion of western Oregon, including the Portland metropolitan area, most of the Willamette Valley and the coastal area from Astoria to Coos Bay. We also hold certificates from the WUTC granting us exclusive rights to serve portions of three southern Washington counties bordering the Columbia River. Gas service is provided in 120 cities and neighboring communities, in 15 Oregon counties, and in 14 cities and neighboring communities, in three Washington counties. The city of Portland is the principal retail and manufacturing center in the Columbia River Basin, and is a major port for trade with Asia.

At year-end 2005, we had 556,667 residential customers, 59,543 commercial customers and 881 industrial sales customers. Approximately 90 percent of our customers are located in Oregon and 10 percent are in Washington. Industries served include pulp, paper and other forest products; the manufacture of electronic, electrochemical and electrometallurgical products; the processing of farm and food products; the production of various mineral products; metal fabrication and casting; the production of machine tools, machinery and textiles; the manufacture of asphalt, concrete and rubber; printing and publishing; nurseries; government and educational institutions; and electric generation.

Interstate Gas Storage

The interstate gas storage business segment is comprised of storage services and third party asset optimization. Approximately 2 percent of our consolidated assets are related to the interstate gas storage business segment. For each of the years ended Dec. 31, 2005, 2004 and 2003, this business segment derived a majority of its revenues from fewer than five storage customers. The largest of these customers is served under a long-term contract.

Interstate Gas Storage Services. This business segment is engaged in providing natural gas storage and related transportation services to interstate customers using storage capacity that has been developed in advance of core utility customers' (residential, commercial and industrial firm) requirements. Under agreements with the OPUC and WUTC, we share with our core utility customers a portion of our net income before tax from interstate gas storage services.

Third Party Optimization Services. We have a contract with an independent energy marketing company that optimizes the value of our assets by engaging in trading activities using temporarily unused portions of off-system pipeline transportation capacity and gas storage capacity (optimization services). In addition, we have entered into a series of exchange transactions with this company with respect to our forward gas supply contracts. See Part II, Item 7., "Comparison of Gas Distribution Operations—Business Segments Other than Local Gas Distribution—Interstate Gas Storage."

Core Utility Customer Sharing. In Oregon, we retain 80 percent of the pre-tax income from interstate gas storage services and optimization when the costs of storage and pipeline transportation capacity used has not been included in core utility rates, and retain 33 percent of the pre-tax income from such optimization when the capacity costs have been included in core utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for the benefit of our core utility customers. We have a similar sharing mechanism in Washington for revenue derived from gas storage services and third party optimization.

Other

We have non-regulated investments in NNG Financial Corporation (Financial Corporation) (see "Subsidiaries," below), a Boeing 737-300 aircraft leased to Continental Airlines and miscellaneous other non-regulated activities. Less than 1 percent of our consolidated assets is related to activities in the "Other" business segment.

Subsidiaries

Financial Corporation

We currently operate only one direct, active subsidiary, Financial Corporation. Financial Corporation, a wholly-owned subsidiary incorporated in Oregon, holds financial investments including limited partnership interests in two wind power electric generation projects located in California and two low-income housing projects in Portland, Oregon. On Jan. 31, 2005, Financial Corporation sold its limited partnership interests in three solar electric generating plants located in California. Financial Corporation also has one active, wholly-owned subsidiary, KB Pipeline Company, which owns a 10 percent interest in an 18-mile interstate natural gas pipeline. As a part owner of the pipeline, KB Pipeline is subject to certain regulations enacted by the Federal Energy Regulatory Commission (FERC) with respect to the Standards of Conduct for Transmission Providers.

Gas Supply and Transportation

General

We meet the needs of our core utility customers through natural gas purchases from a variety of suppliers. We have a diverse portfolio of short-, medium- and long-term firm gas supply contracts that we supplement, during periods of peak demand, with gas from storage facilities either owned by or contractually committed to us.

Gas Acquisition Strategy

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

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

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

Diversity of Supply. Our supply and capacity plan is based on forecasted system requirements and takes into account estimated load growth by type of customer, attrition, conservation, distribution system constraints, interstate pipeline capacity and contractual limitations, and the forecasted movement of customers between bundled sales service and transportation-only service.

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

The following table represents the actual and target sources of regional supply:

Regional Supply Basin

Region	2005 Actual	2005-10 Target
Alberta	44%	45%
British Columbia	27%	30%
U.S. Rockies	29%	25%
Mist gas field	0%	<1%
Total	100%	

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

We typically enter into gas purchase contracts for (i) year-round baseload supply, (ii) November–March (winter heating season) baseload supply, (iii) winter heating season contracts where we have the option to call on all, some or none of the supplies on a daily basis, and (iv) spot purchases, taking into account forecasted customer requirements, storage injections and withdrawals and seasonal weather fluctuations. Other less frequent types of contracts include April-October baseload contracts, April-October contracts where the supplier has the option to supply gas to us on a daily basis, and seasonal exchange purchase and sale contracts. We seek to minimize amounts to be purchased on the spot market during the winter heating season to less than 10 percent. A variety of multi-year contract durations are used to avoid having to re-contract all supplies every year. See "Core Utility Market Basic Supply," below.

Liquidity. We purchase our gas supplies at liquid trading points to facilitate competition and transparent pricing. These trading points include NOVA Inventory Transfer (NIT) in Alberta, Huntingdon/Sumas and Station 2 in British Columbia, and receipt points in the Rocky Mountains.

Price Risk Management. There are four general methods that we currently use for managing gas commodity price risk: (i) negotiating fixed prices directly with gas suppliers, (ii) negotiating financial instruments that "swap" into a fixed price from a floating price contract, (iii) negotiating financial instruments that set a ceiling price on a floating price contract (e.g. call option) and (iv) buying gas and injecting it into storage. See "Cost of Gas," below.

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

Regulatory Alignment. Mechanisms for gas cost recovery are designed to be fair and balanced for customers and shareholders. Because we do not earn a return on the gas commodity acquisition, we attempt to minimize risks associated with cost recovery through:

- the use of purchased gas cost adjustment mechanisms approved by regulatory authorities (see "Regulation and Rates—Rate Mechanisms," below);
- aligning customer and shareholder interests through sharing in the structure of cost recovery and asset optimization mechanisms; and
- periodic review of regulatory deferrals with state regulatory commissions and key customer groups.

Cost of Gas

The cost of gas to supply our core utility market primarily consists of the purchase price paid to suppliers plus charges paid to pipelines to transport the gas to our distribution system. While the rates for pipeline transportation and storage services are subject to federal regulation, the purchase price of gas is not. Although pipeline rates have been relatively stable in recent years, natural gas commodity prices have increased dramatically due to growing demand for natural gas, especially for power generation, stagnant North American gas production, and surging alternative fuel prices. We are in a favorable position with respect to gas production because of the proximity of our service territory to supply basins in western Canada and the Rocky Mountains, where some growth in gas production is expected to continue for the foreseeable future. Management believes growth in gas commodity supply into the North American market is needed to alleviate price pressures. While new federal energy legislation may help ease certain supply concerns in the future, for example by streamlining the certification process for new liquefied natural gas (LNG) import terminals, we believe the legislation offers little to relieve the tight supply situation in the immediate future.

We seek to mitigate the effects of higher gas commodity prices and price volatility on core utility customers through the use of our underground storage facilities, by entering into natural gas commodity-based financial hedge contracts and by crediting gas costs with margin revenues derived from off-system sales of commodity and released transportation capacity in periods when core utility customers do not fully utilize firm pipeline capacity and gas supplies. For our core utility customers, these mechanisms helped to mitigate in part the extreme volatility in gas prices experienced after supply disruptions caused by hurricanes Katrina, Rita and other storms in the Gulf of Mexico during 2005.

Managing the Cost of Gas

We have an active natural gas commodity price hedge program that is intended to reduce commodity price risk. Under this program, we typically enter into commodity swap and call option agreements for the coming year and up to three years into the future, when natural gas prices may be lower. Gains (losses) from commodity hedges are treated for accounting and rate purposes as reductions (increases) to the cost of gas. The intended effect of this program is to lock in prices for between 85 percent and 95 percent of our gas supply portfolio for the following year at prevailing market prices at the time the swap and call option agreements are entered into. Fixed prices have been secured for lesser amounts of gas purchases for the subsequent two years, which helps stabilize future costs and reduce variations in annual rate changes.

Source of Supply—Design Day Sendout

The effectiveness of our gas supply program is largely dependent on the sources from which the design day sendout requirement is satisfied. A design day is the maximum anticipated demand on the natural gas distribution system during a 24-hour period assuming weather at an average temperature of 12° F, the coldest day in the last 20 years in our service territory. We assume that all interruptible customers will be curtailed on the design day. Our projected sources of delivery for design day firm utility customer sendout is 8.9 million therms. We are currently capable of meeting 63 percent of our firm customer design day requirements with storage and peaking supply sources. Optimal utilization of storage and peaking facilities on our design day reduces the dependency on firm transportation. On Jan. 5, 2004, we experienced a record firm customer sendout of 7.2 million therms, and a total sendout of 8.9 million therms, on a day that was approximately 9° F warmer than the design day temperature. That January 2004 cold weather event lasted about ten days, and the actual firm customer sendout each day provided data indicating that load forecasting models required very little re-calibration. Accordingly, we believe that our supplies would be sufficient to meet firm customer demand if we were to experience design day conditions.

The following table reflects the sources of supply that are projected to be used to satisfy the design day sendout for the 2005-2006 winter heating season:

Projected Sources of Supply for Design Day Sendout

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

We believe the combination of the natural gas supplies we can purchase under contract, our peaking supplies and the capacity held under contract on the interstate pipelines will be sufficient to satisfy the needs of existing customers and allow for growth in future years.

Core Utility Market Basic Supply

We purchase gas for our core utility customers from a variety of suppliers located in the western United States and Canada. About 75 percent of our annual supply comes from Canada, with the balance coming primarily from the U.S. Rocky Mountain region. At Jan. 1, 2006, we had 36 firm contracts with 11 suppliers and remaining terms ranging from three months to nine years, which provide for a maximum of 2.8 million therms of firm gas per day during the peak winter heating season and 1.3 million therms per day during the remainder of the year. These contracts have a variety of pricing structures and purchase obligations. During 2005, we purchased 848 million therms of gas under the following contract durations:

Contract Duration (primary terms)	Percent of Purchases
Long-term (10 years or longer)	13
Medium-term (1 to 10 years)	47
Short-term (less than one year)	19
Spot (up to 30 days)	21
Total	100

We regularly renew or replace our expiring long-term and medium-term contracts with new agreements with a variety of existing and new suppliers. Aside from the optimization of our core utility gas supplies by our independent marketing company (see "Asset Optimization," above), no single contract amounts to more than 200,000 therms per day or 10 percent of our average daily contract volumes. Firm year-round supply contracts have primary terms ranging from one to ten years. All of the contracts use price formulas tied to monthly index prices, primarily at the NIT trading point in Alberta. We hedge a majority of our contracts each year using financial instruments as part of our gas purchasing strategy (see "Managing the Cost of Gas," above).

In addition to the year-round contracts, we continue to contract in advance for firm gas supplies to be delivered only during the winter heating season primarily under short-term contracts. During 2004 and 2005, new short-term purchase agreements were entered into with eight suppliers. These agreements have a variety of pricing structures and provide for a total of up to 1.7 million therms per day during the 2005-2006 heating season. We intend to enter into new purchase agreements in 2006 for equivalent volumes of gas with our existing or other similar suppliers, as needed, to replace short-term and one-year contracts that will expire during 2006.

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

We continue to purchase gas from a non-affiliated producer in the Mist gas field in Oregon. The production area is situated near our underground gas storage facility. The price for this gas is tied to our weighted average cost of gas. Current production is approximately 21,000 therms per day from about 18 wells, supplying less than 1 percent of our total annual purchase requirements. Production from these wells varies as existing wells are depleted and new wells are drilled.

Core Utility Market Peaking Supply

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

We have contracts with Williams Gas Pipeline–West, also known as Northwest Pipeline, for firm gas storage services from an underground storage facility at Jackson Prairie near Centralia, Washington, and an LNG facility at Plymouth, Washington. Together, these facilities provide us with daily firm deliverability of about 1.1 million therms and total seasonal capacity of about 16 million therms. Separate contracts with Northwest Pipeline provide for the transportation of these storage supplies to our service territory. All of these contracts have reached the end of their primary terms, but we have exercised our renewal rights that allow for annual extensions at our option.

We own and operate two LNG plants in our service territory that liquefy gas during the summer months for storage until the peak winter heating season. These two plants provide a maximum combined daily deliverability of 1.8 million therms and a total seasonal capacity of 17 million therms.

We also provide daily and seasonal peaking from our underground gas storage facility in the Mist gas field. Including the latest expansions in 2005, this facility has a maximum daily deliverability of 4.4 million therms and a total seasonal working gas capacity of 13.9 Bcf. In September 2004, we completed and placed into service our South Mist pipeline extension project, which completed the transmission pipeline from our Mist gas storage field to growing portions of our distribution service area. Also in 2004, a total of 400,000 therms per day of Mist storage capacity, which had been available for interstate gas storage services, was recalled and committed to use for core utility customers. This was the first instance of returning capacity that had been developed in advance of core utility customers needs for interstate gas storage services to core utility customers under the regulatory agreement with the OPUC. Under this agreement, storage capacity is recalled as needed and added to retail utility rate base at our original cost less accumulated depreciation. The core utility market now has 2.3 million therms per day of deliverability and 8.9 Bcf of working gas committed from the Mist storage facility.

In December 2005, we completed our latest expansion of the Mist gas storage facility. This investment increased the facility's incremental capacity and total daily delivery capacity. All of this expansion is initially being used to serve growth in the interstate gas storage services market. Ultimately, this expansion also will be available to serve the needs of our core utility customers. The expansion increased working gas capacity at Mist to 13.9 Bcf, with 5 Bcf allocated to interstate gas storage services. As the needs of core utility customers grow, existing interstate gas storage capacity will be transferred for use by core utility customers and tracked into retail rates. Newly developed interstate gas storage capacity can then be developed at Mist to replace this recalled storage.

We also have contracts with one electric generator and two industrial customers that together provide an additional 52,000 therms per day of year-round upstream capacity, plus 450,000 therms per day of recallable capacity and supply. Two of these three contracts renew from year to year, while the third will expire in 2010.

Transportation

Dependence on a Single Pipeline. We are directly connected to a single interstate pipeline, Northwest Pipeline. Although we are dependent on a single pipeline, the pipeline is bi-directional as it transports gas into the Portland metropolitan market from two directions: (i) the north, which brings supplies from British Columbia and Alberta supply basins and (ii) the east, which brings supplies from Alberta and the Rocky Mountain supply basins. We are investigating options to further diversify our pipeline transportation paths. The need for pipeline transportation diversity has been underscored by past Northwest Pipeline ruptures and the resulting federal order in 2003 that requires Northwest Pipeline to replace its 26-inch mainline from the Canadian border to our service territory by December 2006.

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

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

Our second largest transportation agreement with Northwest Pipeline extends through 2011. It provides 1.0 million therms per day of firm transportation capacity from the point of interconnection of the Northwest Pipeline and Gas Transmission Northwest (GTN) systems in eastern Oregon to our service territory. GTN's pipeline runs from the U.S./Canadian border through northern Idaho, southeastern Washington and central Oregon to the California/Oregon border. Our total capacity on GTN and two upstream pipelines in Canada (Alberta Natural Gas Company and NOVA Corporation of Alberta, which, with GTN, are all now units of TransCanada PipeLines Limited) matches this amount of Northwest Pipeline capacity northward into Alberta, Canada.

We also have an agreement with Northwest Pipeline that extends through 2013 for approximately 350,000 therms per day of firm transportation capacity. This agreement accesses gas supplies in the U.S. Rocky Mountain region.

We also have four long-term pipeline transportation contracts with other interstate transporters. A contract with Duke Energy Gas Transmission (formerly Westcoast Energy, Inc.) extends through October 2014 and provides approximately 600,000 therms per day of firm gas transportation from northern British Columbia to a connection with Northwest Pipeline at the U.S./Canadian border. A contract with Terasen Gas extends through October 2020 and provides approximately 470,000 therms per day of firm gas transportation from southeastern British Columbia to the same connection with Northwest Pipeline at the U.S./Canadian border. Our capacity with Terasen Gas is matched with companion contracts for pipeline capacity on systems of TransCanada Pipelines in both British Columbia and Alberta, allowing purchases to be made from the gas fields of Alberta, Canada.

Regulation and Rates

NW Natural provides gas utility service in Oregon and Washington and, accordingly, we are subject to regulation with respect to, among other matters, rates, systems of accounts and issuance of securities by the OPUC and the WUTC. Service in Oregon represents over 90 percent of the utility's revenues and cash flows.

We are exempt from the provisions of the Natural Gas Act (Hinshaw exemption) by order of FERC, except with respect to the terms and conditions associated with our interstate gas storage and related transportation services.

General Rate Cases

Our most recent general rate increase in Oregon, which was effective Sept. 1, 2003, authorized rates designed to produce a return on shareholders' equity (ROE) of 10.2 percent. Our most recent general rate case in Washington, which was effective July 1, 2004, authorized a revenue increase of $3.5 million per year but did not specifically authorize an ROE.

In May 2005, we reached a settlement with the FERC staff and all intervenors with respect to our rate case filed in January 2005 related to our interstate storage services. The settlement provided for a small net increase in the maximum rates for our interstate storage services operation and new storage service offerings. The new maximum rates are designed to reflect updated costs related to development of the Mist gas storage facilities since 2001 and costs associated with the South Mist pipeline extension project. The new rates were effective July 1, 2005.

Rate Mechanisms

Weather Normalization. In November 2003, the OPUC authorized, and the utility implemented, a weather normalization mechanism in Oregon that helps stabilize utility margins by adjusting residential and commercial customer billings based on temperature variances from average weather. For purposes of calculating the weather normalization adjustment, actual daily temperatures are compared to 25-year average temperatures for each specified day. 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. The weather normalization mechanism applies only to Oregon residential and commercial customers, and the adjustment is in effect on customer bills from Nov. 15 to May 15 of each heating season. See Part II, Item 7., "Comparison of Gas Distribution Operations."

As part of the approval of our weather normalization mechanism, we were required to file a report reviewing the first two years of the mechanism's operation. The report concluded that the weather normalization mechanism provides benefit to both the utility and its customers and was extended through September 2008, with minor changes resulting from the OPUC's review, and the weather normalization mechanism will remain in effect through September 2008.

Purchased Gas Adjustment. In Oregon, we have a purchased gas adjustment (PGA) tariff under which utility margin derived from Oregon operations may be affected within defined limits by changes in purchased gas costs. The PGA tariff provides for annual revisions in rates resulting from changes in our cost of purchased gas. Costs included in the PGA adjustments are based on our projected gas requirements and negotiated gas prices for the upcoming gas supply contract year. Under our Washington PGA, we track 100 percent of the increases and decreases in gas commodity costs into customer rates, with the result that utility margin is not directly affected by changes in commodity costs. In both Oregon and Washington, the PGA mechanism permits us to recover 100 percent of FERC-approved pipeline transportation costs.

The Oregon PGA tariff provides that 67 percent of any difference between actual purchased gas costs and estimated purchased gas costs incorporated into rates will be deferred for refund (or recovery) in customer rates in subsequent periods. If actual gas commodity costs exceed those incorporated in rates, we subsequently will adjust our rates upward to recover 67 percent of the increased gas costs from core utility customers. Similarly, if actual gas commodity costs are lower than those reflected in rates, rates will be adjusted downward to distribute to core utility customers 67 percent of such gas commodity cost savings.

The OPUC has a formalized process that tests for excessive earnings in connection with gas utilities' annual filings under their PGA mechanisms. The OPUC has confirmed our ability to pass through 100 percent of our prudently incurred gas costs into rates. Under this requirement, we are authorized to retain all of our earnings up to a threshold level equal to our authorized ROE of 10.2 percent plus 300 basis points. One-third of any earnings above that level will be refunded to customers. The excess earnings threshold is subject to adjustment up or down each year depending on movements in long-term interest rates.

In 2004, the OPUC staff initiated a review of gas purchasing strategies for all three local gas distribution companies serving Oregon customers, and a report was issued by the OPUC in June 2005. The OPUC reviewed and acknowledged the report and accepted the OPUC staff's proposed administrative recommendations. Although the report did not result in any change in our gas purchasing strategies, as a result of the OPUC's review and the 2005 PGA increase, the OPUC staff initiated a series of informal workshops to discuss the Oregon PGA mechanism design. We believe it is likely that a formal proceeding will be established to determine if changes to the current PGA mechanism are warranted.

Conservation Tariff. In October 2002, the OPUC authorized the implementation of a "conservation tariff," which is a mechanism designed to adjust margin revenues to compensate the utility for declining usage due to residential and commercial customers' conservation efforts. The tariff was a partial decoupling mechanism that was intended to break the link between earnings and the quantity of energy consumed by customers, removing any profit incentive to discourage customers from taking measures to reduce energy use. On average, residential and commercial customers have continued to reduce energy consumption over the past several years in response to the impact of higher energy prices on their utility bills and increased awareness of energy efficiency programs.

The conservation tariff includes two components. The first component is a price elasticity adjustment, which adjusts for anticipated increases or decreases in consumption attributable to annual changes in commodity costs or periodic changes in our general rates. The second component is a conservation adjustment calculated on a monthly basis to account for deviations between actual and expected volumes (decoupling adjustment). Additional charges or credits to customers resulting from the decoupling adjustment are recorded to a deferral account, which is included in the next year's annual PGA. Baseline consumption was determined by customer consumption data used in the 2003 Oregon general rate case, adjusted for added consumption resulting from new customers. See Part II, Item 7., "Results of Operations—Comparison of Gas Distribution Operations."

In 2005, an independent study to measure the mechanism's effectiveness was completed. The study recommended continuation of the conservation tariff, which was scheduled to expire at the end of September 2005, with minor modifications. In 2005, the OPUC approved the continuation of the conservation tariff for an additional four years, through Sept. 30, 2009, and increased the mechanism's coverage from a partial decoupling of 90 percent of residential and commercial gas usage to a full decoupling of 100 percent.

Pipeline Integrity Cost Recovery. In July 2004, the OPUC approved our applications relating to the accounting treatment and full recovery for the cost of the pipeline integrity management program, as mandated by the Pipeline Safety Improvement Act of 2002 and related rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (see Part II, Item 7., "Financial Condition—Cash Flows—Investing Activities"). The accounting and rate treatment for these costs extends through Sept. 30, 2008 and may be reviewed for potential extension after that date.

OPUC Audit

In 2004, the OPUC approved a stipulation among NW Natural, the OPUC staff and two parties in our 2003 Oregon general rate case. The stipulation provided for the settlement of issues in an investigation initiated by the OPUC in 2003 relating to our transactions or interests in certain properties in the vicinity of our headquarters building in downtown Portland, and the use of some of these properties for employee parking. We agreed in the stipulation to undergo and pay for an audit in 2005. The audit, which was completed in 2005, focused on financial hedging transactions, deferred taxes, tax credits, our Coos Bay distribution system project, securities issuances, the calculation of allowance for funds used during construction, and affiliated interest transactions. The auditors issued a report in December 2005 with no material findings involving financial adjustments. The report's findings and recommendations primarily focused on the need for increased documentation of policies and procedures in financial areas, a review of our procurement policies, and strengthening of our cost allocation procedures for affiliated interests.

Utility Regulation Legislation

In 2005, the Oregon legislature passed Senate Bill (SB) 408 requiring the OPUC to establish an annual tax adjustment to ensure that Oregon utilities do not collect more income taxes in rates than they actually pay to government entities. SB 408 is effective for taxes collected on or after Jan. 1, 2006. The bill, which was signed into law on Sept. 2, 2005, requires that the OPUC interpret the bill's provisions to determine how the tax adjustment will be applied. The OPUC has issued temporary rules and, in October 2005, we filed with the OPUC our first three-year tax report showing the amount of taxes we paid (according to the definitions in SB 408) compared with the amount of taxes we were authorized to collect in rates for each of the calendar years 2002, 2003 and 2004. Our report concluded that, based on the calculations required by the temporary rules, we paid more in income taxes than the amount we were authorized to collect in rates. This report was not required for the purpose of determining rate adjustments, and these results are not necessarily indicative of future calculations. The report, as well as reports submitted by other utilities, is intended to help the OPUC develop rules required to implement SB 408. Due to the uncertainties related to the OPUC's interpretations and rule making with respect to the application of the legislation's provisions, we are not able to determine at this time what impact, if any, the new legislation will have on our financial condition, results of operations or cash flows, but the impact may be material.

Integrated Resource Plan

The OPUC and WUTC have implemented integrated resource planning processes under which utilities develop plans defining alternative growth scenarios and resource acquisition strategies. Our most recent integrated resource plan was filed in Oregon and Washington in 2005. Elements of the plan included: an evaluation of supply and demand resources; the consideration of uncertainties in the planning process and the need for flexibility to respond to changes; a primary goal of "least cost" service; and consistency with state energy policy. Although the OPUC's order acknowledging the integrated resource plan does not constitute ratemaking approval of any specific resource acquisition or expenditure, the OPUC generally indicates that it would give considerable weight in prudency reviews to utility actions that are consistent with acknowledged plans. Elements of our draft integrated resource plan demonstrate that the continued development of the Mist underground gas storage facility is the least-cost option for serving customer growth.

Additions to Infrastructure

We expect a high level of capital expenditures for additions to infrastructure over the next five years, reflecting projected customer growth, system replacement, improvement and reinforcement projects and the development of additional gas storage facilities. Estimated capital expenditures in 2006 total $104 million, and for the years 2006-10 such expenditures are estimated at between $500 and $600 million. We continue to be one of the fastest growing gas utilities in the nation (see "Competition and Marketing," below). In 2005, our customer base grew by more than 3 percent for the 19th year in a row, and we expect to continue that trend in 2006.

Pipeline Safety

The Pipeline Safety Improvement Act of 2002 and related regulations require operators of gas transmission pipelines to identify lines located in High Consequence Areas (HCAs) and develop integrity management programs to periodically inspect the integrity of the pipelines and make repairs or replacements as necessary to ensure the ongoing safety of the pipelines. The legislation and related regulations require us to complete inspection of 50 percent of the highest risk pipelines located in our HCAs within the first five years, and the remaining covered pipelines within 10 years of the date of enactment. We are also required to re-inspect the covered pipelines every seven years from the date of the previous inspection for the life of the pipelines. See Part II., Item 7., "Financial Condition—Cash Flows—Investing Activities." We have met the first major milestones required by the act.

Effective Jan. 12, 2005, we assumed responsibilities as operator of an approximately 60-mile pipeline that transports gas from Northwest Pipeline to Coos County, Oregon. The pipeline safety requirements of the act will also apply to us as operator of that pipeline.

We entered into a stipulation with the OPUC in 2001 for an enhanced pipeline safety program that includes an accelerated bare steel replacement program and a geo-hazard safety program. The bare steel program accelerates the replacement of our bare steel piping over 20 years instead of 40 years. The geo-hazard safety program includes the identification, assessment and remediation of potential risks to piping infrastructure created by landslides, washouts, earthquakes or similar occurrences. The stipulation allows us to receive deferred accounting rate treatment for costs associated with the bare steel program exceeding $3 million per year and the actual costs associated with the geo-hazard safety program. The regulatory authority for the geo-hazard safety program is scheduled to expire on Dec. 31, 2006.

Competition and Marketing

Competition with Other Energy Products

We have no direct competition in our service area from other natural gas distributors. However, for residential customers' heating needs, we compete with electricity, fuel oil, propane and, to a lesser extent, wood. We also compete with electricity and fuel oil for commercial applications. In the industrial market, we compete with all forms of energy, including gas-to-gas competition from third-party sellers of natural gas commodity. Competition among these forms of energy is based on price, reliability, efficiency and performance.

The competitive price advantage of natural gas over electricity declined in 2005 due to higher natural gas commodity prices and relatively stable electricity prices in both the residential and commercial markets. The current price advantage varies due to differences in retail electric rates between investor-owned utilities, where we have maintained a moderate price advantage, and the public utilities, where our price advantage, if any, is marginal. In 2005, although electricity prices continued to become more competitive primarily due to improving end use technology, natural gas retained its relative price advantage compared to electricity provided by the investor-owned utilities that serve approximately 75 percent of the homes in our Oregon service area. We expect to maintain a price advantage compared to electricity provided by the investor-owned electric utilities in part because a growing portion of the electricity sold by these utilities is generated from natural gas. Although the price advantage for natural gas compared to oil continued to be favorable in 2005, there were fewer residential conversions from heating oil to natural gas during 2005 due to volatile gas prices and a decline in the remaining inventory of potential oil conversion opportunities.

Residential and Commercial Markets

The relatively low market saturation of natural gas in residential single-family and attached dwellings in our service territory, estimated at approximately 50 percent, together with the price advantage of natural gas compared with electricity in some areas and our operating convenience over fuel oil, provides the potential for continuing growth from residential and commercial conversions. In 2005, 19,515 net residential customers (after subtracting disconnected or terminated services) were added, including existing residential housing that converted from oil, electric or propane appliances to natural gas. The net increase of all new customers added in 2005 was 20,528. This represents a growth rate of 3.4 percent, which is about twice the national average for local gas distribution companies as reported by the American Gas Association.

Industrial Markets

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

Competition to serve the industrial and large commercial market in the Pacific Northwest has been relatively steady since the early 1990s in terms of numbers and types of competitors. Competitors consist of gas marketers, oil/propane sellers and electric utilities. Wood-based fuels continue to lose market share in these markets primarily due to environmental concerns and restrictions.

The OPUC and WUTC have approved transportation tariffs under which we may contract with customers to deliver customer-owned gas. Transportation tariffs available to industrial customers are priced at our cost of providing transportation service. Generally, we are unaffected financially if industrial customers transport customer-owned gas rather than purchasing gas from us, as long as they remain on a tariff or contract with the same quality of service. However, industrial customers may select between firm and interruptible service, among other different levels or qualities of service, and these choices can positively or negatively affect margin revenue from such customers. The relative level and volatility of prices in the natural gas commodity markets, the availability of interstate pipeline capacity to ship customer-owned gas and the cost structure embedded in our industrial rates are among the primary factors that have caused some industrial customers to alternate between sales and transportation service or between higher and lower qualities of service. We re-designed our industrial rates in Oregon and Washington as part of our general rate cases in 2003 and 2004, respectively, in order to better reflect relative costs of service and to become more competitive in the industrial market. Our larger commercial and industrial customers may elect to switch between sales and transportation service upon a minimum of 30 days formal notice. Upon switching forms of service, the customer is then obligated to remain on that type of service for at least 12 months, at which time they once again may elect to switch upon 30 days notice. In the case of customers switching from transportation to sales service, our regulatory tariff provides that the customer will be charged incremental gas supply costs.

Our industrial customer segment, which includes customers in the high-tech, forest products and other industries that are sensitive to economic conditions, showed modest but continued margin improvement in 2005. Sales service to industrial customers increased in 2005 compared to previous years because spot and forward gas prices were higher than the weighted average cost of gas embedded in our sales rates. The mix within the industrial market between firm and interruptible service was different in 2005, with deliveries under industrial firm service tariffs constituting 38 percent of total industrial deliveries in 2005, compared to 43 percent in 2004.

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

Environmental Matters

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

- the complexity of the site;
- changes in environmental laws and regulations at the federal, state and local levels;
- the number of regulatory agencies or other parties involved;
- new technology that renders previous technology obsolete, or experience with existing technology that proves ineffective;
- the ultimate selection of technology;

- the level of remediation required; and
- variations between the estimated and actual period of time that must be dedicated to respond to an environmentally-contaminated site.

We own or previously owned properties currently being investigated that may require environmental response, including a property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956, a property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation, and an area adjacent to the Gasco site and the Siltronic site along a segment of the Willamette River that has been listed by the U.S. Environmental Protection Agency as a Superfund site for which we have been identified as one of a number of potentially responsible parties. We do not expect that the ultimate resolution of these matters will have a material adverse effect on our financial condition or results of operations. See Note 12 to the accompanying Consolidated Financial Statements for a further discussion of potential environmental responses and related costs.

Employees

At Dec. 31, 2005, we had 1,305 employees, of which 893 were members of the Office and Professional Employees International Union (OPEIU), Local No. 11, AFL-CIO. We have a labor agreement (Joint Accord) with members of OPEIU covering wages, benefits and working conditions that will expire on May 31, 2009.

Available Information

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

We have adopted a Code of Ethics for all employees and a Financial Code of Ethics that applies to senior financial employees, both of which are available on our website. Our Corporate Governance Standards, Director Independence Standards, charters of each of the committees of the Board of Directors and additional information about us are also available on the website.

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

ITEM 1A. RISK FACTORS

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

The rates we charge customers for gas distribution services are established by the OPUC and the WUTC. The failure to approve rates which provide for recovery of our costs and an adequate return on invested capital may adversely impact our financial condition and results of operations.

The rates and terms at which the utility resells gas to its customers or transports gas owned by large customers from the interstate pipeline connection to the customers' facilities must be approved by the OPUC or the WUTC. The rates are designed to allow us to recover costs of providing such services and to earn an adequate return on our capital investment. We expect to continue to make significant capital expenditures to expand and improve our distribution system. The failure of the OPUC or the WUTC to approve on a timely basis requested rate increases to recover increased costs or to allow an adequate return could adversely impact our financial condition and results of operations.

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

In recent years, natural gas commodity prices have increased dramatically due to growing demand, especially for power generation, and stagnant North American gas production. In Oregon, the utility has a Purchased Gas Adjustment (PGA) tariff which provides for annual revisions in rates resulting from changes in the cost of purchased gas. The PGA tariff provides that 33 percent of any difference between actual purchased gas costs and estimated purchased gas costs incorporated into rates will be recognized as current income or expense. Accordingly, higher gas costs than those assumed in setting rates can adversely affect our results of operations.

Notwithstanding our current rate structure, higher gas costs could result in increased pressure on the OPUC or the WUTC to seek other means to reduce rates to a level that could adversely affect our results of operations and financial condition.

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

Our gas purchasing requirements expose us to risks of commodity price movements. We attempt to manage our exposure through enforcement of established risk limits and risk management procedures, including hedging activities. These risk limits and risk management procedures may not always work as planned and cannot eliminate the risks associated with gas purchasing and hedging. These practices are subject to regulatory review in setting our PGA tariffs and, if found to be imprudent, could be disallowed.

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

A large portion of the utility's margin is derived from sales to space heating residential and commercial customers between November 15 and May 15 of each winter heating season. Current rates are based on an assumption of average weather. Although we have a weather normalization mechanism in effect in Oregon, approximately 10 percent of our residential and commercial customers are in Washington, where the mechanism is not in effect, and about 9 percent of the eligible Oregon customers elected not to be covered by the mechanism, so the mechanism does not fully insulate us from utility earnings volatility due to weather. Also, customer usage between May 15 and November 15 is not subject to the weather normalization mechanism. As a result, we are not fully protected against warmer than average weather, which may have an adverse affect on our results of operations.

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

Higher gas costs and rates may result in increased conservation by customers, which can decrease sales and adversely affect results of operations. The OPUC authorized our conservation tariff, which is designed to recover lost margin due to changes in residential and commercial customers' consumption patterns. The conservation tariff is intended to adjust for increases or decreases in consumption attributable to annual changes in commodity costs or periodic changes in general rates and for deviations between actual and expected usage. The conservation tariff expires in September 2009. The failure of the OPUC to extend the conservation tariff in the future could adversely affect our financial condition and results of operations.

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

We own, or previously owned, properties that may require environmental remediation or other action. We accrue all material loss contingencies relating to these properties, but our results of operations may be adversely affected to the extent that estimates of the probable costs increase significantly as additional information on the cost of the remediation process is developed. Although a regulatory asset has been recorded for some of these estimated costs, we would be required to reduce such regulatory asset if we were unable to conclude that recovery of these costs through rates is probable. If this occurs and if such costs are not recoverable through insurance, our results of operations and financial condition could be adversely affected.

Also, we cannot predict with certainty the amount or timing of future expenditures related to the environmental investigation and remediation because of the difficulty of estimating such costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties.

There are no assurances that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to us. Revised or additional regulations which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our results of operations.

Our gas distribution business is subject to increased competition and eroding price advantage.

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

Higher natural gas prices have eroded or, in some cases, eliminated the competitive price advantage of natural gas over alternative energy sources. If the higher gas price environment is sustained, our ability to attract new customers could be significantly affected, which could have a negative impact on our customer growth rate and results of operations.

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

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

Our results of operations may be impacted by utility regulation legislation enacted by state legislatures.

On Aug. 1, 2005, the Oregon legislature passed Senate Bill 408, effective for taxes collected on or after Jan. 1, 2006, which requires the OPUC to establish an annual tax adjustment to ensure that

Oregon utilities do not collect in rates more income taxes than they actually pay to government entities. The bill, which was signed into law on Sept. 2, 2005, requires that the OPUC interpret the bill's provisions to determine how the tax adjustment will be applied. Key provisions of the bill require utilities to determine the amount of taxes collected in rates, the amount of taxes paid to government entities and the amount of tax savings realized as a result of filing consolidated tax returns. Due to the uncertainties related to the OPUC's interpretations and permanent rule making with respect to the application of these provisions, we are not able to determine at this time what impact, if any, the new legislation will have on our financial condition, results of operations or cash flows, but the impact may be material.

Our larger industrial customers may switch between transportation and sales service on short notice, which could significantly impact our ability to forecast customer load requirements when contracting for gas supplies.

Our larger commercial and industrial customers may elect to switch between sales and transportation service upon a minimum of 30 days formal notice. Upon switching forms of service, the customer is then obligated to remain on that type of service for at least 12 months, at which time they once again may elect to switch upon 30 days notice. In the case of customers switching from transportation to sales service, our regulatory tariff provides that the customer will be charged incremental gas supply costs. We face risks to the extent we must purchase or sell gas supplies to match up with customer load requirements that may change upon short notice from these customer elections, particularly if we are or would be providing sales service at a fixed price to the customer.

The cost of providing pension and post-retirement benefit plans is subject to changes in pension assumptions, fluctuations in the market value of plan assets and changing demographics, and may have a material effect on our financial results.

We maintain two qualified non-contributory defined benefit pension plans, several non-qualified supplemental pension plans and other post-retirement benefit plans. We may be required to recognize a material increase or decrease in annual pension or post-retirement benefit expense based on changes in assumed interest rates, market returns, rate of wage increases and other factors, and we may be required to record a charge to our balance sheet to the extent that benefit obligations exceed the fair value of the plan assets.

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

Our gas distribution activities involve a variety of inherent hazards and operating risks, such as leaks, accidents and mechanical problems, which could cause substantial financial losses. In addition, these risks could result in loss of human life, significant damage to property, environmental pollution and disruption of our operations, which in turn could lead to substantial losses. The occurrence of any of these events may not be covered by our insurance policies or recoverable through rates, which could adversely affect our financial condition and results of operations.

ITEM 2. PROPERTIES

Our natural gas distribution system consists of 13,187 miles of distribution and transmission mains. In addition, the distribution system includes service pipes, meters and regulators, and gas regulating and metering stations. The mains and feeder lines are located in municipal streets or alleys pursuant to valid franchise or occupation ordinances, in county roads or state highways pursuant to valid agreements or permits granted pursuant to statute, or on lands of others pursuant to valid easements obtained from the owners of such lands. We also hold all necessary permits for the crossing of the Willamette River and a number of smaller rivers by our mains.

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

We hold interests in 7,934 net acres of underground natural gas storage and 1,780 net acres of oil and gas leases in Oregon. We own rights to depleted gas reservoirs near Mist, Oregon, that are continuing to be developed 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 order to reduce risks associated with gas leakage in older parts of our system, we undertook an accelerated pipe replacement program in the 1980s under which we removed or replaced 100 percent of our cast iron mains by October 2000. In 2001, we initiated an accelerated pipe replacement program under which we will reduce the amount of bare steel mains in the system.

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 currently planned additions, adequate for our present and foreseeable future needs.

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

ITEM 3. LEGAL PROCEEDINGS

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

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

There were no matters submitted to a vote of security holders, through the solicitation of proxies or otherwise, during the quarter ended Dec. 31, 2005.

PART II

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

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

The quarterly high and low trades for NW Natural's common stock during the past two years were as follows:

	2005		2004	
Quarter Ended	High	Low	High	Low
March 31	$37.24	$32.42	$33.00	$29.95
June 30	38.67	34.36	31.65	27.46
September 30	39.63	35.60	32.37	28.84
December 31	37.77	33.25	34.13	30.77

The closing quotations for the common stock on Dec. 30, 2005 and Dec. 31, 2004 were $34.18 and $33.74, respectively.

(B) As of Dec. 31, 2005, there were 9,136 holders of record of our common stock.

(C) NW Natural has paid quarterly dividends on its common stock in each year since the stock first was issued to the public in 1951. Annual common dividend payments have increased each year since 1956. Dividends per share paid during the past two years were as follows:

Payment Date	2005	2004
February 15	$0.325	$0.325
May 15	0.325	0.325
August 15	0.325	0.325
November 15	0.345	0.325
Total per share	$1.320	$1.300

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

NW Natural maintains a Dividend Reinvestment and Direct Stock Purchase Plan under which participants may reinvest all or a portion of their quarterly dividends in additional shares of common stock at the current market price. Prior to December 2005, we satisfied the requirements of the plan through the issuance of original issue shares. Beginning in December 2005, we commenced purchasing shares required for the plan in the open market. In the eleven months ended Nov. 30, 2005, dividend reinvestments and optional cash investments under the plan aggregated $4.1 million and resulted in the issuance of 113,925 shares of common stock. During the 28 years the plan has been available, we have issued and sold 4,765,361 shares of common stock, which produced $107.0 million in additional capital.

(D) The following table provides information about purchases by us during the quarter ended Dec. 31, 2005 of equity securities that are registered pursuant to Section 12 of the Exchange Act:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares Purchased[1]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[2]	(d) Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
Balance forward			733,300	$12,988,108
10/01/05-10/31/05	-	-	-	-
11/01/05-11/30/05	-	-	24,800	(857,560)
12/01/05-12/31/05	1,830	$35.30	7,500	(260,085)
Total	1,830	$35.30	765,600	$11,870,463

[1] During December 2005, 1,830 shares of our common stock were purchased in the open market to meet the optional cash purchase requirements of our Dividend Reinvestment and Direct Stock Purchase Plan (DSPP). Previously, the requirements of the DSPP were met by issuing original issue shares of common stock. During the three months ended Dec. 31, 2005, no shares of our common stock were accepted as payment for stock option exercises pursuant to our Restated Stock Option Plan.

[2] On May 25, 2000, we announced a program to repurchase up to 2 million shares, or up to $35 million in value, of NW Natural's common stock through a repurchase program that has been extended annually. The purchases are made in the open market or through privately negotiated transactions. Since the program's inception, we have repurchased 765,600 shares of common stock at a total cost of $23.1 million. In April 2005, NW Natural's Board of Directors extended the program through May 31, 2006.

ITEM 6. SELECTED FINANCIAL DATA

Thousands, except per share amounts and ratio of earnings to fixed charges	For the year ended Dec. 31, 2005	2004	2003	2002	2001
Utility operating revenues:					
Residential sales	$ 460,204	$ 380,832	$ 328,346	$ 354,735	$ 329,905
Commercial sales	244,824	199,444	176,336	201,475	190,236
Industrial - firm sales	64,247	44,625	33,578	42,965	49,662
Industrial - interruptible sales	100,740	55,380	23,655	15,937	34,283
Unbilled revenues	17,021	3,849	14,474	(12,702)	13,774
Total gas sales revenues	887,036	684,130	576,389	602,410	617,860
Transportation	10,755	12,655	17,968	26,020	20,637
Other	2,862	4,160	7,627	4,018	(2,325)
Total utility gross operating revenues	900,653	700,945	601,984	632,448	636,172
Cost of gas sold	563,772	399,176	323,128	353,034	364,699
Revenue taxes	21,633	16,865	14,650	14,743	14,645
Utility net operating revenues	315,248	284,904	264,206	264,671	256,828
Non-utility net operating revenues	9,745	6,591	9,210	8,130	4,538
Net operating revenues	$ 324,993	$ 291,495	$ 273,416	$ 272,801	$ 261,366
Net income	$ 58,149	$ 50,572	$ 45,983	$ 43,792	$ 50,187
Redeemable preferred and preference stock dividend requirements	-	-	294	2,280	2,401
Earnings applicable to common stock	$ 58,149	$ 50,572	$ 45,689	$ 41,512	$ 47,786
Average common shares outstanding:					
Basic	27,564	27,016	25,741	25,431	25,159
Diluted	27,621	27,283	26,061	25,814	25,612
Earnings per share of common stock:					
Basic	$ 2.11	$ 1.87	$ 1.77	$ 1.63	$ 1.90
Diluted	$ 2.11	$ 1.86	$ 1.76	$ 1.62	$ 1.88
Dividends per share of common stock	$ 1.32	$ 1.30	$ 1.27	$ 1.26	$ 1.245
Total assets - at end of period	$2,042,031	$1,732,195	$1,585,379	$1,467,277	$1,550,653
Redeemable preferred stock	$ -	$ -	$ -	$ 8,250	$ 9,000
Redeemable preference stock	$ -	$ -	$ -	$ -	$ 25,000
Long-term debt	$ 521,500	$ 484,027	$ 500,319	$ 445,945	$ 378,377
Ratio of earnings to fixed charges	3.32	3.02	2.84	2.85	3.14

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

SELECTED FINANCIAL DATA (continued)

Thousands, except customer and gas cost per therm data	2005	2004	2003	2002	2001
Capitalization - at end of period					
Common stock equity	$ 586,931	$ 568,517	$ 506,316	$ 482,392	$ 468,161
Redeemable preference stock	-	-	-	-	25,000
Redeemable preferred stock	-	-	-	8,250	9,000
Long-term debt	521,500	484,027	500,319	445,945	378,377
Total capitalization	$1,108,431	$1,052,544	$1,006,635	$ 936,587	$ 880,538
Gas sales and transportation deliveries (therms):					
Residential	366,990	356,199	343,534	357,091	350,065
Commercial	231,896	226,490	226,257	240,155	242,293
Industrial - firm	74,963	63,149	55,314	63,215	79,778
Industrial - interruptible	149,106	104,278	47,994	26,241	63,597
Unbilled therms	6,556	(7,764)	12,099	(6,617)	1,771
Total gas sales	829,511	742,352	685,198	680,085	737,504
Transportation	328,056	389,514	414,554	445,999	385,783
Total volumes delivered	1,157,567	1,131,866	1,099,752	1,126,084	1,123,287
Customers (average for period):					
Residential	545,163	525,976	510,336	492,871	474,373
Commercial	58,914	57,973	56,504	55,416	54,628
Industrial - firm	666	629	362	350	377
Industrial - interruptible	201	178	98	74	141
Transportation	78	106	179	190	111
Total customers	605,022	584,862	567,479	548,901	529,630
Customer statistics:					
Heat requirements					
Actual degree days	4,178	3,853	3,952	4,232	4,325
Percent colder (warmer) than average	(2%)	(10%)	(7%)	(1%)	1%
Average annual use per customer in therms:					
Residential	673	677	673	725	738
Commercial	3,936	3,907	4,004	4,334	4,435
Gas purchased cost per therm - net (cents)	71.42	56.60	46.99	51.07	47.19

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 financial condition including the principal factors that affect results of operations. The discussion refers to our consolidated activities for the three years ended Dec. 31, 2005. References in this discussion to "Notes" are to the notes to the consolidated financial statements in this report.

The consolidated financial statements include the accounts of Northwest Natural Gas Company, a regulated utility, and its non-regulated businesses, including its wholly-owned subsidiary business, NNG Financial Corporation (Financial Corporation). 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 interstate gas storage business (interstate gas storage) and other non-regulated activities (other) (see Note 2).

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

Executive Summary

Our strategy in 2005 was to remain focused on profitably growing our regulated utility and interstate gas storage businesses. The utility is our largest business segment with approximately 98 percent of consolidated total assets and 91 percent of consolidated net income in 2005. Factors critical to the success of the utility include maintaining a safe and reliable distribution system, acquiring natural gas supplies and providing distribution services at a competitive price, and being able to recover the operating and capital costs of the utility in the rates charged to customers. The utility is regulated by two state commissions, the Oregon Public Utility Commission (OPUC) and the Washington Utilities and Transportation Commission (WUTC).

The interstate gas storage segment represents approximately 2 percent of consolidated total assets and 9 percent of consolidated net income in 2005. This business provides services to large interstate customers using storage and transportation capacity and asset optimization services provided under an agreement with an independent energy marketing company. Factors critical to the success of our interstate gas storage business include the ability to develop additional storage capacity at competitive market prices and to plan for the replacement of capacity that is expected to be recalled by the utility to serve its core (residential, commercial and industrial firm) customers in the future.

Highlights of 2005 include:

- A 13 percent increase in earnings per share, driven by a 12 percent increase in net income from the utility and a 58 percent increase in net income from interstate gas storage;
- an 11 percent increase in utility net operating revenues (utility margin), reflecting increases from all customer sectors (residential, commercial and industrial);
- over $89 million of utility gas cost savings realized from our financial gas hedging program, including $59 million in the fourth quarter, which helped to partially offset a dramatic rise in gas prices following the hurricanes in the Gulf of Mexico in August and September;

- a net increase of 20,528 utility customers, for an annual growth rate in excess of 3 percent for the 19th consecutive year;
- expansion of our Mist storage facility, enhancing our ability to serve the interstate market;
- a 6 percent increase in the indicated annual dividend rate per share, making this the 50th consecutive year of increasing dividends paid to shareholders;
- refinanced a $200 million credit line at attractive rates, providing sufficient liquidity to address higher gas prices;
- issued $50 million of long-term debt, using the proceeds to redeem higher-priced debt and fund capital expenditures;
- received regulatory approval of the utility's conservation tariff, extending the margin stabilization mechanism for another four years; and
- Updated our strategic plan, focusing on cost controls and efficiency improvements.

Issues, Challenges and Performance Measures

There are a number of factors that affect our operations and financial performance. The most significant issue the utility faces in the near term is higher gas prices. Wholesale gas prices over the past few years have increased significantly, primarily due to increasing demand. In 2005, the gas supply market tightened as hurricanes hit parts of the United States, resulting in the disruption of gas supplies and causing gas prices to spike. Although gas prices moderated in early 2006, we expect prices to remain higher than in the past few years. Higher gas prices are already reflected in our customers' bills for the 2005-06 heating season. We believe we have sufficient supplies of natural gas under contract to meet the needs of our firm customers, but further price increases could change our competitive advantage and our customers' preference for natural gas. If higher gas prices persist, it could significantly affect our ability to add residential and commercial customers and could result in industrial customers shifting their businesses' energy needs to alternative fuel sources.

Other issues and challenges we expect to face in 2006 include unpredictable weather conditions, the potential impact of adverse regulatory actions or policy changes, managing gas supplies, storage and transportation capacity, managing customer growth, maintaining a competitive advantage over alternative fuels, managing environmental risks and exposures and higher interest rates. For a more detailed discussion of these and other risks, see "Item 1A—Risk Factors," above, and "Forward-Looking Statements" and "Quantitative and Qualitative Disclosures About Market Risk," below.

Our strategic plan addresses the risks affecting our business by focusing on:

- improving our ability to add customers profitably;
- maintaining our reputation for exemplary customer service;
- reducing business risks;
- managing all costs, including capital expenditures;
- setting high performance standards for all employees; and
- judiciously growing beyond our local distribution business where such growth would complement core assets and competencies.

Return on equity and common equity ratios are key indicators of our operating performance and financial condition. We compare our utility return on equity results each year against the return on equity authorized by the OPUC. We also compare our consolidated return on equity results against a peer group of local gas distribution companies because it is necessary for us to attract investors so that we can continue to raise the capital needed to run our businesses. Other key performance measures we use in monitoring progress against our goals include earnings per share, customer satisfaction ratings, customer additions, operations and maintenance expense per customer, construction cost per meter installed, and non-revenue producing capital expenditures per customer.

Earnings and Dividends

Earnings applicable to common stock were $58.1 million, or $2.11 a diluted share, for the year ended Dec. 31, 2005, compared to $50.6 million, or $1.86 a share, and $45.7 million, or $1.76 a share, for the years ended Dec. 31, 2004 and 2003, respectively. Returns on equity for these three years were 10.1 percent, 9.4 percent and 9.3 percent, respectively.

2005 compared to 2004:

Positive factors contributing to increased earnings included:

- increased utility volumes and margins (utility net operating revenues) from sales to residential and commercial customers due to 3.4 percent customer growth, 8 percent colder weather and conservation tariff mechanisms, partially offset by declining average use per customer and a decrease in the contribution from the weather normalization mechanism—$23.6 million (see "Results of Operations—Comparison of Gas Distribution Operations," below, and "Results of Operations—Regulatory Matters—Rate Mechanisms," below;
- decreased utility volumes but increased utility margin from industrial customers, primarily reflecting a shift of several customers to higher margin service which offset the overall decline in volumes – $1.1 million;
- increased utility margin from miscellaneous revenues – $1.5 million; and
- increased interstate gas storage margin over the prior year primarily due to increased storage services under contract and optimization – $3.2 million.

Partially offsetting the above positive factors were:

- increased operations and maintenance expense related to increased payroll and employee benefit costs ($5.3 million), increased damages to Company property ($1.0 million), industrial customer settlement charges ($2.0 million) and employee severance charges ($0.9 million);
- increased property tax and depreciation expenses related to increased utility plant in service ($5.4 million), which were partially covered by revenue increases approved in the most recent general rate cases in Oregon and Washington; and
- increased income tax expense related to higher net income – ($6.2 million).

2004 compared to 2003:

Positive factors contributing to increased earnings included:

- increased contribution to utility margin from residential and commercial customers primarily resulting from the Oregon and Washington general rate increases, including rate increases for certain capital investments and a full-year effect of the weather normalization mechanism – $25.2 million; and
- increased utility margin contribution from industrial customers resulting from a recovering economy – $3.2 million.

Partially offsetting the above positive factors were:

- decreased margin from other utility operating revenues due to changes in and amortizations under regulatory deferral mechanisms – ($7.8 million);
- increased payroll and related payroll tax, pension and health care costs primarily due to wage and salary increases and certain benefit cost increases – ($4.6 million);
- internal development costs and external audit fees relating to the implementation of Section 404 of the Sarbanes-Oxley Act of 2002 – ($1.5 million);
- increases in depreciation and property taxes due to added utility plant – ($3.8 million);
- decreased margin from interstate gas storage due to less optimization margin reflecting lower volatility in natural gas price differentials – ($2.6 million);
- reduced income from non-utility subsidiary investments, including a $0.5 million charge for the sale of solar electric generating investments – ($0.3 million); and
- increased income taxes – ($3.2 million).

Dividends paid on common stock were $1.32 a share in 2005, compared to $1.30 a share in 2004 and $1.27 a share in 2003. The current indicated annual dividend rate is $1.38 per share.

Application of Critical Accounting Policies and Estimates

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

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

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

Regulatory Accounting

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

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

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

We continue to apply SFAS No. 71 in accounting for our regulated utility operations. Future regulatory changes or changes in the competitive environment could require us to discontinue the application of SFAS No. 71 for some or all of our regulated business. This would require the write-off of those regulatory assets and liabilities that would no longer be probable of recovery from or refund to customers. Based on current regulatory and competitive conditions, we believe that it is reasonable to expect continued application of SFAS No. 71 for our regulated activities, and that all of our regulatory assets and liabilities at Dec. 31, 2005 and 2004 are recoverable or refundable through future customer rates. See Note 1, "Industry Regulation."

Revenue Recognition

Utility revenues, derived primarily from the sale and transportation of natural gas, are recognized when the gas is delivered to and received by the customer. Revenues are accrued for gas delivered to customers but not yet billed based on estimates of gas deliveries from the last meter reading date to month end (accrued unbilled revenues). Accrued unbilled revenues are primarily based on a percentage estimate of our unbilled gas each month, which is dependent upon a number of factors some of which require management's judgment. These factors include total gas receipts and deliveries, customer meter reading dates, customer usage patterns and weather. Accrued unbilled revenue estimates are reversed the following month when actual billings occur. Estimated unbilled revenues at Dec. 31, 2005 and 2004 were $81.5 million and $64.4 million, respectively. The increase in accrued unbilled revenues at year-end 2005 was primarily due to higher gas prices included in customer rates and higher volumes reflecting colder weather, partially offset by decreases in customer usage due to higher prices. If the estimated percentage of unbilled volume at Dec. 31, 2005 was adjusted up or down by 1 percent, then our unbilled revenues, net operating revenues and net income would have increased or decreased by an estimated $2.3 million, $1.0 million and $0.6 million, respectively.

In November 2003, we implemented a weather normalization mechanism in Oregon that helps stabilize net operating revenues by adjusting current customer billings based on temperature variances from average weather (see "Results of Operations—Regulatory Matters—Rate Mechanisms," below). Weather normalization is also included in accrued unbilled revenues at the end of each accounting period.

Non-utility revenues, derived primarily from interstate storage services, are recognized upon delivery of the service to customers. Revenues from optimization of excess storage and transportation capacity are recognized over the life of the contract for guaranteed amounts under the contract, or are recognized as they are earned for amounts above the guaranteed value based on information provided by the independent energy marketing company.

Accounting for Derivative Instruments and Hedging Activities

In the normal course of business, we enter into natural gas commodity purchase contracts using physical assets owned or contractually obligated to the utility, including gas storage and pipeline transportation capacity. Prior to 2005, these purchase contracts qualified for the normal purchase and normal sale exception as defined by SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149 (collectively referred to as SFAS No. 133) (see "Interstate Gas Storage," below, and Note 11). In 2005, we entered into an agreement providing for natural gas commodity exchange transactions with our optimization partner, which involved exchanging gas purchases originally intended for delivery to utility customers, for an equivalent volume of gas from our optimization partner and received at our city gate. These exchanges resulted in our gas purchase contracts no longer qualifying for the normal purchase and normal sale exception under SFAS No. 133 and required that they be accounted for as derivative instruments and marked-to-market based on fair value pursuant to SFAS No. 133, effective March 31, 2005. The mark-to-market adjustment at Dec. 31, 2005 resulted in a net unrealized loss of $4.1 million, which was recorded on the balance sheet at fair value. Generally, these physical gas purchases are subject to regulatory deferral, and, as such, any unrealized gain or loss in the fair value is not recognized in current income but is recorded as a regulatory asset or regulatory liability pursuant to SFAS No. 71 and included in annual cost of gas in rate changes under our PGA tariffs (see Note 1). Our estimate of fair value is determined by an internal model based on natural gas index prices that are subject to market volatility and an evaluation of counterparty credit risk (see Part II, Item 7A., "Quantitative and Qualitative Disclosures About Market Risk"). As a result of these forward gas purchase contracts being classified as derivatives for accounting purposes, any related financial derivative instruments previously designated as hedge instruments of the underlying physical gas purchase contracts no longer qualify for hedge accounting under SFAS No. 133. Therefore, the corresponding financial derivative contracts are no longer designated as cash flow hedges although they continue to economically hedge the financial risk exposure of the underlying physical gas purchase contracts. The change from hedge accounting treatment had no income statement effect due to the application of SFAS No. 71 for unrealized gains and losses on hedge contracts expected to be included in the calculation of annual PGA rate changes.

Our Derivatives Policy sets forth guidelines for using selected financial derivative products to support prudent risk management strategies within designated parameters. The policy specifically prohibits the use of derivatives for trading or speculative purposes. These contracts that qualify as derivative instruments are recorded on the balance sheet at fair value. Generally, these contracts are subject to regulatory deferral, and any change in the fair value is recorded as regulatory assets or regulatory liabilities pursuant to SFAS No. 71 (see Note 1). Our estimate of fair value is determined from period to period based on an internal discounted cash flow model using forward prices that are subject to market volatility. For estimated fair values at Dec. 31, 2005 and 2004, see Note 11.

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

Thousands	2005	2004	2003
Net gain on commodity-price swap contracts	$90,205	$44,888	$29,660
Net gain (loss) on commodity-price option contracts	(1,315)	(2,464)	2,723
Subtotal	88,890	42,424	32,383
Net loss on commodity-price swaps related to storage	-	(186)	-
Net gain on foreign currency forward purchase contracts	532	219	4,129
Total realized gains on commodity and currency contracts	$89,422	$42,457	$36,512

Realized gains (losses) from commodity-price and foreign currency forward purchase contracts are recorded as reductions (increases) to the cost of gas and are included in the calculation of annual PGA rate changes. Unrealized gains and losses resulting from mark-to-market valuations are not recognized in current income or other comprehensive income, but are recorded as regulatory liabilities or regulatory assets, which are offset by a corresponding balance in non-trading derivative assets or liabilities (see Note 11).

Accounting for Pensions

We have two qualified, non-contributory defined benefit pension plans covering all regular employees with more than one year of service. These plans are funded through a trust dedicated to providing retiree pension benefits. We also have several non-qualified supplemental pension plans for eligible executive officers and certain key employees. These non-qualified plans are unfunded.

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

A number of factors are considered in developing pension assumptions, including an evaluation of relevant discount rates, expected long-term returns on plan assets, plan asset allocations, expected changes in wages and retirement benefits, analyses of current market conditions and input from actuaries and other consultants. For the Dec. 31, 2005 measurement date, we:

- decreased the discount rate assumption from 6.00 percent to 5.75 percent;
- updated the mortality rates to reflect longer life expectancies;
- included a $20 million contribution in September 2005 and an additional $11 million in December 2005;
- maintained the rate of compensation increase in a range of 4.00-5.00 percent; and
- maintained the expected long-term return on plan assets at 8.25 percent.

The benefit obligation at Dec. 31, 2005 increased $26.6 million due to the change in mortality rates, and $8.1 million due to the 0.25 percent change in the assumed discount rate.

The discount rate at Dec. 31, 2005 was determined by developing a spot rate yield curve using the pension plans' estimated future benefit payments applied to a portfolio of Moody's AA or better rated bonds.

We determine the expected long-term rate of return by averaging the expected earnings for the target asset portfolio. In developing our expected rate of return assumption, we evaluate an analysis of historical actual performance and long-term return projections which gives consideration to the asset mix and our target asset allocation. The annualized returns for the past one-year, five-year and 10-year periods ended Dec. 31, 2005 were 7.4 percent, 5.9 percent and 10.1 percent, respectively.

We believe our pension assumptions to be appropriate based on plan design and an assessment of market conditions. However, the following reflects the sensitivity of net period pension cost and accumulated benefit obligation to future changes in certain actuarial assumptions:

Thousands, except percent	Change in Assumption	Impact on 2005 NPPC	Impact on ABO at Dec. 31, 2005
Discount rate	(0.25%)	$739	$6,893
Expected long-term return on plan assets	(0.25%)	$437	N/A

The impact of a change in net periodic pension cost on operating results would be less than the amounts shown above because approximately 60 percent of net periodic pension cost is charged to current operations and maintenance expense. The remaining 40 percent is capitalized as construction overhead and included in utility plant, which is amortized to expense over the useful life of the asset placed into service.

Accounting for Income Taxes

Income taxes are accounted for in accordance with SFAS No. 109, "Accounting for Income Taxes," by recognizing deferred income taxes for all temporary differences between the book and tax bases of assets and liabilities at current income tax rates.

SFAS No. 109 also requires the recognition of additional deferred income tax assets and liabilities for temporary differences where regulators flow through deferred income tax benefits or expenses in the ratemaking process of the regulated utility (regulatory tax assets and liabilities). This is consistent with the ratemaking policies of the OPUC and WUTC. Regulatory tax assets and liabilities are recorded to the extent we believe they will be recoverable from or refunded to customers in future rates. At Dec. 31, 2005 and 2004, we had regulatory assets representing differences between book and tax bases related to pre-1981 property of $65.8 million and $64.7 million, respectively, and recorded an offsetting deferred tax liability for the same amounts (see Note 1). We believe that it is reasonable to expect recovery of these regulatory assets through future customer rates. However, future regulatory changes could require the write-off of all or a portion of these regulatory assets should they no longer be probable of recovery in future rates (see "Regulatory Accounting," above, and Note 1, "Industry Regulation," below).

Contingencies

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

With respect to our environmental liabilities and related costs, we develop estimates based on currently available information, existing technology and environmental regulations. We previously received regulatory approval to defer and seek recovery of costs related to certain sites and believe the recovery of any costs not recovered under our general liability insurance policies is probable through the regulatory process (see Note 12). In accordance with SFAS No. 71, we recorded a regulatory asset for the amount expected to be recovered. We intend to first pursue recovery for these environmental costs from our general liability insurance policies, which, to the extent successful, would require a corresponding reduction in the regulatory asset. At Dec. 31, 2005, $18.8 million in environmental costs have been recorded as a regulatory asset, including $12.4 million of costs paid to-date and $6.4 million accrued for estimated future environmental costs. If it is determined that both the insurance recovery and future rate recovery of such costs are not probable, then the costs will be charged to expense in the period such determination is made. An application for extension of the regulatory approval to defer environmental costs is pending.

Results of Operations

Regulatory Matters

Regulation and Rates

We are subject to regulation with respect to, among other matters, rates, systems of accounts and issuance of securities by the OPUC and the WUTC. In 2005, 93 percent of our utility gas deliveries and 91 percent of our utility operating revenues were derived from Oregon customers and the balance from Washington customers. Future earnings and cash flows from utility operations will be determined largely by the pace of continued growth in the residential and commercial markets and by our ability to remain price competitive, control expenses, and obtain reasonable and timely regulatory recovery for our operating and maintenance costs and investments made in utility plant.

General Rate Cases

Our most recent general rate increase in Oregon, which was effective Sept. 1, 2003, authorized rates designed to produce an ROE of 10.2 percent. In Washington, the WUTC approved a general rate increase, which became effective on July 1, 2004, but no specific ROE was authorized.

In May 2005, we reached a settlement with the Federal Energy Regulatory Commission (FERC) staff and all intervenors with respect to our rate case filed in January 2005 related to our interstate storage services. The settlement provided for a small net increase in the maximum rates for our interstate storage services operation and new service offerings. The new maximum rates are designed to reflect updated costs related to development of the Mist gas storage facilities since 2001 and costs associated with the South Mist pipeline extension project. The new rates were effective July 1, 2005.

Rate Mechanisms

Purchased Gas Adjustment. Rate changes are applied each year under the PGA mechanisms in NW Natural's tariffs in Oregon and Washington to reflect changes in the costs of natural gas commodity purchased under contracts with gas producers (see "Comparison of Gas Distribution Operations—Cost of Gas Sold," below), the application of temporary rate adjustments to amortize balances in regulatory asset or liability accounts and the removal of temporary rate adjustments effective the previous year. Pursuant to the PGA tariffs, rate increases were approved by the OPUC, averaging 15.2 percent for Oregon residential sales customers, and by the WUTC, averaging 12.0 percent for Washington residential sales customers, both effective Oct. 1, 2005.

In 2004, the OPUC approved a PGA rate increase averaging 20.1 percent for Oregon residential sales customers, and the WUTC approved a PGA rate increase averaging 19.5 percent for Washington residential sales customers, effective Oct. 1 and Nov. 1, 2004, respectively. In 2003, the OPUC approved PGA rate increases averaging 3.5 percent for Oregon residential sales customers, and the WUTC approved PGA rate increases averaging 16.8 percent for Washington residential sales customers, both effective on Oct. 1, 2003.

The OPUC has formalized a process that tests for excess earnings in connection with gas utilities' annual filings under the PGA mechanisms. The OPUC has confirmed our ability to pass through 100 percent of prudently incurred gas costs into rates. Under this requirement, we are authorized to retain all of our earnings up to a threshold level equal to our authorized ROE of 10.2 percent plus 300 basis points. One-third of any earnings above that level will be refunded to customers. The excess earnings threshold is subject to adjustment up or down each year depending on movements in interest rates. No amounts were required to be refunded to customers as a result of the 2004 or 2003 earnings test. NW Natural does not expect any amounts to be refunded to customers as a result of the 2005 earnings test, which will be reviewed by the OPUC during the second quarter of 2006.

Weather Normalization. In November 2003, we implemented a weather normalization mechanism in Oregon that is designed to stabilize margins from weather-sensitive residential and commercial customers by adjusting current billings based on temperature variances from average weather. For purposes of calculating the weather normalization adjustment, actual daily temperatures are compared to 25-year average temperatures for each specified day. 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. As part of the approval for our weather normalization, we were required to provide a report evaluating the first two years of the mechanism in the fall of 2005. The report concluded that the weather normalization mechanism provides benefit to both the utility and its customers and was extended through September 2008, with minor changes resulting from the OPUC's review.

Conservation Tariff. In 2002, the OPUC authorized a conservation tariff, which is a mechanism designed to recover lost margin due to changes in residential and commercial customers' consumption patterns. The tariff is a decoupling mechanism that is intended to break the link between our earnings and the quantity of gas consumed by our customers, so that we do not have an incentive to discourage customers' conservation efforts.

In August 2005, the OPUC approved a four-year extension of the conservation tariff, through Sept. 30, 2009, and increased the mechanism's coverage from a partial decoupling of 90 percent of residential and commercial gas usage to a full decoupling of 100 percent.

Pipeline Integrity Cost Recovery. In July 2004, the OPUC approved our applications relating to the accounting treatment and full recovery for the cost of the pipeline integrity management program as mandated by the Pipeline Safety Improvement Act of 2002 and related rules adopted by the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration (see "Financial Condition—Cash Flows—Investing Activities"). Under the applications as approved, we classify our costs as either capital expenditures or regulatory assets, accumulate the costs over each 12-month period ending June 30, and recover the costs, subject to audit, through rate changes effective on October 1 of each year. The accounting and rate treatment for these costs extends through Sept. 30, 2008, and may be reviewed for potential extension after that date.

Service Quality Measures

Service Quality Measure—Conservation Tariff. As part of the initial proceeding approving the conservation tariff, we agreed to adopt certain service quality measures that establish a performance goal for the number of complaints by customers where we are determined to be at fault. If we exceed the prescribed level of at-fault complaints, we are subject to penalties. Since inception, we have not incurred any penalties under these service quality measures.

Oregon Billing Service Quality Measure. In 2005, the OPUC approved a billing service quality measure for Oregon customers that requires billing accuracy, after certain exclusions, of 99.4 percent each month. If billing accuracy falls below 99.4 percent, a remedy of $50,000 per month may be imposed, up to a maximum of $0.3 million per year. The quality measure became effective Jan. 1, 2006. We do not expect the billing service quality measure to have a material effect on our financial condition, results of operations or cash flows.

Utility Regulation Legislation

In 2005, the Oregon legislature passed Senate Bill (SB) 408 requiring the OPUC to establish an annual tax adjustment to ensure that Oregon utilities do not collect more income taxes in rates than they actually pay to government entities. SB 408 is effective for taxes collected on or after Jan. 1, 2006. The bill, which was signed into law on Sept. 2, 2005, requires that the OPUC interpret the bill's provisions to determine how the tax adjustment will be applied. The OPUC has issued temporary rules and, in October 2005, we filed with the OPUC our first three-year tax report showing the amount of taxes we paid (according to the definitions in SB 408) compared with the amount of taxes we were authorized to collect in rates for each of the calendar years 2002, 2003 and 2004. Our report concluded that, based on the calculations required by the temporary rules, we paid more in income taxes than the amount we were authorized to collect in rates. This report was not required for the purpose of determining rate adjustments, and these results are not necessarily indicative of future calculations. The report, as well as reports submitted by other utilities, is intended to help the OPUC develop rules required to implement SB 408. Due to the uncertainties related to the OPUC's interpretations and rule making with respect to the application of the legislation's provisions, we are not able to determine at this time what impact, if any, the new legislation will have on our financial condition, results of operations or cash flows, but the impact may be material.

Comparison of Gas Distribution Operations

The following table summarizes the composition of gas utility volumes and revenues for the three years ended Dec. 31:

Thousands, except degree day and customer data	2005		2004		2003	
Utility volumes - therms:						
Residential and commercial sales	605,442	52%	574,925	51%	581,890	53%
Industrial sales and transportation	552,125	48%	556,941	49%	517,862	47%
Total utility volumes sold and delivered	1,157,567	100%	1,131,866	100%	1,099,752	100%
Utility operating revenues - dollars:						
Residential and commercial sales	722,049	80%	$ 584,125	83%	$ 519,156	87%
Industrial sales and transportation	175,742	20%	112,660	16%	75,201	12%
Other revenues	2,862	0%	4,160	1%	7,627	1%
Total utility operating revenues	$ 900,653	100%	$ 700,945	100%	$ 601,984	100%
Cost of gas sold	563,772		399,176		323,128	
Revenue taxes	21,633		16,865		14,650	
Utility net operating revenues (margin)	$ 315,248		$ 284,904		$ 264,206	
Margin[1]						
Residential sales	$ 195,269	62%	$ 172,209	60%	$ 159,353	60%
Commercial sales	79,044	25%	70,565	25%	64,220	25%
Industrial - firm sales and transportation	15,146	4%	14,615	5%	10,176	4%
Industrial - interruptible sales and transportation	16,951	5%	16,411	6%	17,614	7%
Miscellaneous revenues	4,990	2%	3,472	1%	3,794	1%
Other margin adjustments	2,215	1%	(1,939)	-1%	3,578	1%
Margin before weather normalization and decoupling	313,615	99%	275,333	96%	258,735	98%
Weather normalization mechanism	(1,334)	0%	7,873	3%	1,838	1%
Decoupling mechanism	2,967	1%	1,698	1%	3,633	1%
Utility net operating revenues (margin)	$ 315,248	100%	$ 284,904	100%	$ 264,206	100%
Total number of customers (end of year)	617,163		596,635		578,150	
Actual degree days	4,178		3,853		3,952	
Percent colder (warmer) than average	(2%)		(10%)		(7%)	
(25-year average degree days is used as average)						

[1] Amounts reported as margin for each category of customers is net of demand charges and revenue taxes. In prior years, customer margin by category did not reflect these costs but have been revised to be consistent with the current year's presentation. We believe the current presentation is a better representation of the margin earned from each class of customer.

Total utility volumes sold and delivered in 2005 increased 2 percent compared to 2004, and volumes sold and delivered in 2004 increased 3 percent compared to 2003.

Our customer base continued to grow in 2005, with a net increase of 20,528 customers. The growth rate for 2005 was 3.4 percent compared to 3.2 percent for both 2004 and 2003. In the three years ended Dec. 31, 2005, more than 57,000 customers were added to the system, representing an average annual growth rate of 3.3 percent.

Our utility results are affected by customer growth and by changes in weather and customer consumption patterns, with a significant portion of our earnings being derived from natural gas sales to residential and commercial customers. In 2002, the OPUC approved a conservation tariff that adjusts margin up or down based on changes in residential and commercial customer consumption; and in 2003, the OPUC approved a weather normalization mechanism that adjusts customer bills, and our margin, based on above- or below-average temperatures during the winter heating season (see "Results of Operations—Regulatory Developments—Rate Mechanisms," above). Both mechanisms are designed to reduce the volatility of our utility earnings.

2005 compared to 2004:

In 2005, weather was 8 percent colder than 2004, which contributed largely to a 13 percent increase in margin from residential and commercial sales. The weather normalization mechanism reduced margin by $1.3 million for the year ended Dec. 31, 2005 based on weather that was actually 2 percent warmer than average. The mechanism contributed $7.9 million to margin in 2004 based on weather that was 10 percent warmer than average. Generally, we would have expected the weather normalization mechanism to contribute a positive margin contribution when temperatures are warmer than average, but in 2005 we lost heating volumes and corresponding margin in the latter part of May when temperatures were significantly warmer than average, and these volume and margin losses were not covered by the weather normalization mechanism which ends each year on May 15.

The decoupling mechanism contributed $3.0 million to margin in 2005, after adjusting for price elasticity in the annual Oregon PGA, compared to a contribution of $1.7 million in 2004.

Other margin adjustments, which include our share of gas cost savings, unaccounted-for gas charges and other regulatory gas cost and revenue adjustments, increased margin by $2.2 million in 2005 compared to a decrease of $1.9 million in 2004. The decrease in net deductions from other margin adjustments was primarily due to a higher share of gas cost savings in the current year, which amounted to $4.2 million in 2005, as compared to $0.6 million in 2004 (see "Cost of Gas," below).

2004 compared to 2003:

In 2004, margin from residential and commercial sales increased 9 percent due to the full year effect of higher rates resulting from the Oregon general rate increase effective in September 2003 and from the Washington general rate increase effective in July 2004, partially offset by weather that was 3 percent warmer than 2003. The weather normalization mechanism increased margin by $7.9 million for the year ended Dec. 31, 2004 based on weather that was 10 percent warmer than average and contributed $1.8 million to margin in 2003 based on weather that was 7 percent warmer than average. The decoupling mechanism contributed $1.7 million to margin in 2004, after adjusting for price elasticity in the annual Oregon PGA, compared to a contribution of $3.6 million in 2003.

Other margin adjustments, which include our share of gas cost savings, unaccounted-for gas charges and other regulatory gas cost and revenue adjustments, reduced margin by $1.9 million in 2004 compared to an increase of $3.6 million in 2003. The increase in net deductions from other margin adjustments was primarily due to lower off-system gas sales in 2004 compared to 2003.

Residential and Commercial Sales

The following table summarizes the utility volumes and utility operating revenues in the residential and commercial markets. The primary factors that impact the results of operations in these markets are seasonal weather patterns, competitive factors in the energy industry and economic conditions in our service areas.

Thousands, except customers	2005	2004	2003
Utility volumes - therms:			
Residential sales	366,990	356,199	343,534
Commercial sales	231,896	226,490	226,257
Change in unbilled sales	6,556	(7,764)	12,099
Total weather-sensitive utility volumes	605,442	574,925	581,890
Utility operating revenues - dollars:			
Residential sales	$460,204	$380,832	$328,346
Commercial sales	244,824	199,445	176,336
Change in unbilled sales	17,021	3,849	14,474
Total weather-sensitive utility revenues	$722,049	$584,126	$519,156
Total number of customers (end of year)	616,210	595,700	577,396

2005 compared to 2004:

- volumes sold were 5 percent higher, reflecting the impact of 8 percent colder weather and 3.4 percent customer growth; and
- operating revenues were 24 percent higher, primarily due to increased volumes and a 17 percent increase in the average rate per therm due to recent PGA rate increases, effective Oct. 1, 2004 and Oct. 1, 2005 (see "Regulatory Matters—Rate Mechanisms," above).

2004 compared to 2003:

- volumes sold were 1 percent lower, reflecting the effects of 3 percent warmer weather that was partially offset by the impact of 3.2 percent customer growth; and
- operating revenues were 13 percent higher, primarily due to a 14 percent increase in the average rate per therm due to PGA rate increases, effective Oct. 1, 2003 and Oct. 1, 2004 (see "Regulatory Matters—Rate Mechanisms," above).

Typically, 80 percent or more of annual utility operating revenues are derived from gas sales to weather-sensitive residential and commercial customers. Although variations in temperatures between periods will affect volumes of gas sold to these customers, the effect on margin and net income was significantly reduced with the implementation of the weather normalization mechanism in Oregon beginning in November 2003 (see "Regulatory Matters—Rate Mechanisms," above). This mechanism applies to meter readings of participating Oregon customers taken between Nov. 15 and May 15. Approximately 10 percent of our residential and commercial customers are in Washington, where the mechanism is not in effect, and about 9 percent of the eligible Oregon customers elected not to be covered by the mechanism, so the mechanism does not fully insulate us from earnings volatility due to weather. The mechanism decreased margin by a net $1.3 million in the twelve-month period ended Dec. 31, 2005. In 2004, the mechanism contributed $7.9 million of margin and in 2003 the mechanism contributed $1.8 million of margin in the two months after becoming effective in November 2003.

Total utility operating revenues include accruals for gas delivered but not yet billed to customers (accrued unbilled revenues) based on estimates of gas deliveries from that month's meter reading dates to month end. Amounts reported as unbilled operating revenues reflect the increase or decrease in the balance of accrued unbilled revenues compared to the prior year-end. Weather conditions, rate changes and customer billing dates affect the balance of accrued unbilled revenue at the end of each month. At Dec. 31, 2005, accrued unbilled revenue was $81.5 million, compared to $64.4 million at Dec. 31, 2004.

Industrial Sales and Transportation

The following table summarizes the delivered volumes and utility operating revenues in the industrial market:

Thousands, except customers	2005	2004	2003
Utility volumes - therms:			
Industrial - firm sales	74,963	63,149	55,314
Industrial - firm transportation	135,807	176,978	146,693
Industrial - interruptible sales	149,106	104,278	46,327
Industrial - interruptible transportation	192,249	212,536	269,528
Total utility volumes	552,125	556,941	517,862
Utility operating revenues - dollars:			
Industrial - firm sales	$ 64,247	$ 44,625	$ 33,578
Industrial - firm transportation	4,087	5,035	5,241
Industrial - interruptible sales	100,740	55,380	23,655
Industrial - interruptible transportation	6,668	7,620	12,727
Total utility operating revenues	$175,742	$112,660	$ 75,201
Total number of customers (end of year)	953	935	754

2005 compared to 2004:

Total volumes delivered to industrial customers were 4.8 million therms, or 1 percent, lower in 2005 than in 2004, and operating revenues were up $63 million, or 56 percent. The higher revenues reflect a 34 percent increase in sales volumes due to customers that migrated from transportation to sales service, where the cost of gas component is included in revenues, and from rate increases approved in the PGA, effective Oct. 1, 2005 and Oct. 1, 2004.

2004 compared to 2003:

Total volumes delivered to industrial customers were 39 million therms, or 7 percent, higher in 2004 than in 2003, and operating revenues were up $37 million, or 50 percent. The higher volumes and revenues partially reflect an improving economy, but results primarily reflect the shift from transportation to sales service and the reclassification of a relatively large number of customers from the commercial category to the industrial category in the 24 months following implementation of the 2003 rate design changes in Oregon. The number of industrial customers increased 24 percent from 2003 to 2004, reflecting this reclassification. Industrial rates in Oregon were redesigned as part of the general rate case in 2003, transferring $4.8 million of annual revenue requirement from industrial rates to residential and commercial rates in order to better reflect relative costs of service and to improve the competitiveness of our rates in the industrial market.

High natural gas prices resulted in a number of our large industrial customers switching from transportation service, where they arrange for their own supplies through independent third parties, to sales service where we sell the gas commodity under regulatory tariffs. Our tariff requires us to charge the incremental cost of gas supply incurred to serve those customers (see Note 12).

Other Revenues

Other revenues include miscellaneous fee income as well as revenue adjustments reflecting deferrals to, or amortizations from, regulatory asset or liability accounts other than deferrals relating to gas costs (see Note 1). Other revenues increased net operating revenues by $2.9 million in 2005, compared to $4.2 million in 2004 and $7.6 million in 2003. The following table summarizes other revenues by primary category for the last three years:

Thousands	2005	2004	2003
Revenue adjustments:			
Current regulatory deferrals:			
Decoupling mechanism	$ 2,967	$ 1,698	$ 3,633
South Mist pipeline extension	164	1,475	643
Coos Bay distribution system	814	244	-
OPUC investigation	-	(690)	-
Oregon income tax kicker refund	(956)	-	-
Other	(270)	35	82
Current regulatory amortizations:			
Interstate gas storage credits	2,714	5,324	3,057
Decoupling mechanism	(2,975)	(2,952)	(783)
South Mist pipeline extension	(1,862)	(601)	-
Coos Bay distribution system	(282)	-	-
Conservation programs	(2,001)	(2,835)	(2,408)
Year 2000 technology costs	(743)	(1,293)	(949)
Other	1,131	255	558
Net revenue adjustments	(1,299)	660	3,833
Miscellaneous revenues:			
Customer fees	4,327	3,245	3,327
Other	(166)	255	467
Total miscellaneous revenues	4,161	3,500	3,794
Total other revenues	$ 2,862	$ 4,160	$ 7,627

2005 compared to 2004:

Other revenues in 2005 were $1.3 million lower than in 2004 primarily due to a decrease in interstate gas storage credits to customers ($2.6 million) resulting from lower net income from storage operations in 2004 compared to 2003 and the deferral of the Oregon income tax kicker refund ($1.0 million), partially offset by an increase in customer fees from higher late payment fees and a special enhanced service contract ($1.1 million) and an increase in deferrals under the decoupling mechanism ($1.3 million) (see "Regulatory Matters—Rate Mechanisms," above).

2004 compared to 2003:

Other revenues in 2004 were $3.5 million lower than in 2003 primarily due to the decrease in deferrals under the decoupling mechanism ($1.9 million) (see "Regulatory Matters—Rate Mechanisms," above), the increase in amortization of decoupling deferrals from prior periods ($2.2 million) and an increase in other deferral amortizations ($1.6 million), partially offset by higher credits from revenue sharing with core utility customers from our interstate gas storage business ($2.3 million).

Cost of Gas Sold

Natural gas commodity prices have fluctuated significantly in recent years. The effects of higher commodity prices and price volatility on core utility customers are mitigated in part through the use of underground storage facilities, fixed-price commodity hedge contracts and short-term sales of excess gas commodity and transportation capacity to off-system customers in periods when core utility customers do not require the full firm pipeline capacity and gas supplies.

We regularly renew or replace our expiring long-term and medium-term contracts with agreements with a variety of existing and new suppliers. Except for contract volumes under exchange agreements with our asset optimization partner, no single contract amounts to more than 200,000 therms per day or 10 percent of our average daily volumes. Firm year-round supply contracts have primary terms currently ranging from less than one year to nine years. All of the contracts use price formulas tied to monthly index prices, primarily at the NOVA Inventory Transfer trading point in Canada. We hedge a majority of our contracts each year using financial instruments as part of our gas purchasing strategy.

The total cost of gas sold was $563.8 million in 2005, an increase of $164.6 million or 41 percent compared to 2004, and cost of gas sold in 2004 was $76.1 million or 24 percent higher than 2003. The cost per therm of gas sold includes current gas purchases, gas drawn from storage inventory, gains or losses from commodity hedges, margin from off-system gas sales, seasonal demand cost balancing adjustments, regulatory gas cost deferrals and company gas use.

We use a natural gas commodity-price hedge program under the terms of our Derivatives Policy to help manage our exposure to floating price gas commodity contracts (see "Application of Critical Accounting Policies and Estimates—Accounting for Derivative Instruments and Hedging Activities," above, and Note 11). We realized net financial hedge gains of $88.9 million from our financial hedges in 2005, compared to $42.4 million and $32.4 million in 2004 and 2003, respectively. Gains and losses from the financial hedging of utility gas purchases are included in cost of gas, which are factored into our PGA deferrals and annual rate changes, and therefore have no material impact on net income.

Under the PGA tariff in Oregon, our net income is affected within defined limits by changes in purchased gas costs (see "Results of Operations—Regulatory Matters—Rate Mechanisms—Purchased Gas Adjustment," above). In each of the last three years, our actual gas costs were lower than the gas costs embedded in rates, with the effect that our share of the cost savings increased margin by $4.2 million, $0.6 million and $0.3 million for 2005, 2004 and 2003, respectively.

We are able to use gas supplies available but not required for delivery to core market customers, principally due to warmer weather and other changes in gas demand, to make off-system sales. Under the PGA tariff in Oregon, we retain 33 percent of the margins realized from off-system sales and record the remaining 67 percent as a deferred regulatory asset or liability for recovery from, or refund to, customers in future rates. Our share of margin from off-system gas sales in 2005 resulted in a margin gain of $0.2 million compared to a loss of $0.3 million in 2004. Our share of margin from off-system gas sales was significantly higher in 2003, at $4.9 million, reflecting a higher volume of gas available for off-system sales due to warmer weather and significantly higher market prices. We were able to use excess gas supplies available under contract at fixed prices, but not required for delivery to core utility market customers to make these off-system sales at higher market prices. The purchase price for this gas had been fixed through commodity swap and call option contracts entered into earlier at levels substantially below the market prices.

Business Segments Other than Local Gas Distribution

Interstate Gas Storage

We earned $4.6 million in net income from our non-utility interstate gas storage business segment in 2005, after regulatory sharing and income taxes, equivalent to 17 cents a share, compared to $2.9 million or 11 cents a share in 2004 and $4.3 million or 17 cents a share in 2003 (see Note 2). Earnings from this business segment were higher in 2005, primarily due to increased revenues from interstate storage services under contract. A secondary reason was an increase in net revenues from a contract with an independent energy marketing company (the optimization partner) that optimizes the value of our gas supply and storage assets.

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

Subsidiaries

Financial Corporation

Financial Corporation's operating results in 2005 were net income of $0.3 million, compared to $0.2 million in 2004 and $0.7 million in 2003. The decrease in net income in 2005 and 2004 compared to 2003 was primarily due to the write-down and sale of our limited partnership interests in three solar electric generation projects, and the payment of a $2.9 million cash dividend by Financial Corporation to the parent company.

Our investment in Financial Corporation was $3.1 million at Dec. 31, 2005, compared to $5.7 million at Dec. 31, 2004.

Operating Expenses

Operations and Maintenance

Operations and maintenance expenses increased $11.1 million, or 11 percent, in 2005 compared to 2004 and increased $5.7 million, or 6 percent, in 2004 compared to 2003. The following summarizes the major factors that contributed to changes in operations and maintenance expense:

2005 compared to 2004:

- a $3.0 million increase in regular payroll-related expense resulting from employee additions, pay increases and higher benefit costs;
- a $2.3 million increase in bonus payroll expense related to improved results on performance goals and to an increase in the accrued long-term incentive plan liability due to a higher stock price on which the award is based;
- a $2.0 million charge related to a settlement with a group of industrial customers;
- a $1.0 million increase in system damages and damage claims written-off;
- a $0.9 million increase related to employee severance charges;
- a $0.4 million increase in costs for software maintenance; and
- a $0.4 million increase in costs for consumer safety advertising.

Partially offsetting the above increases was:

- a $0.3 million decrease in uncollectible accounts expense reflecting improved collection results and cash recoveries of accounts previously written-off.

2004 compared to 2003:

- a $3.5 million increase in payroll and payroll-related expenses, due to salary and wage increases, and higher pension and health care costs, resulting from a change in the pension discount rate assumption and rising health care premiums (see Note 7);
- a $1.5 million increase in expenses for compliance activities, including external audit fees, relating to the Sarbanes-Oxley Act of 2002;
- a $1.3 million increase in uncollectible accounts expense due to increases in gross revenues stemming from higher rates; and
- a $0.3 million increase in gas technology research costs.

Partially offsetting the above increases were:

- a $0.4 million decrease in workers compensation expense; and
- a $0.8 million decrease in energy efficiency rebate costs.

Most of the cost increases we experienced in 2004 were included in the rates approved in our general rate cases in Oregon and Washington (see "Regulatory Matters—General Rate Cases," above).

General Taxes

General taxes, which are principally comprised of property and payroll taxes, increased $1.2 million, or 6 percent, in 2005 compared to 2004, and increased $1.5 million, or 7 percent, in 2004 compared to 2003.

Payroll taxes decreased $0.5 million in 2005 compared to 2004 and increased $1.1 million in 2004 compared to 2003. In 2004, payroll taxes included taxes on bonuses paid and an accrual for taxes on the 2004 bonus paid in 2005.

Property taxes increased $1.5 million in 2005 and $0.7 million in 2004 primarily due to increased utility plant in service.

Depreciation and Amortization

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

Thousands	2005	2004	2003
Plant and property:			
Utility plant:			
Depreciable	$1,839,206	$1,768,630	$1,591,720
Non-depreciable, including construction work in progress	36,238	26,342	65,869
	1,875,444	1,794,972	1,657,589
Non-utility property:			
Depreciable	36,920	27,109	20,716
Non-depreciable, including construction work in progress	3,917	6,854	2,679
	40,837	33,963	23,395
Total plant and property	$1,916,281	$1,828,935	$1,680,984
Depreciation and amortization:			
Utility plant	$ 60,935	$ 56,899	$ 53,798
Non-utility property	710	472	451
Total depreciation and amortization expense	$ 61,645	$ 57,371	$ 54,249
Average depreciation rate – utility	3.4%	3.4%	3.5%
Average depreciation rate – non-utility	2.6%	2.3%	3.5%

Total depreciation and amortization expense increased by $4.3 million, or 7 percent, in 2005 and by $3.1 million, or 6 percent, in 2004. The increased expense for both years is primarily due to additional investments in utility property that were made to meet continuing customer growth, including our South Mist pipeline extension investment that was put into service in two phases, one in November 2003 and the other in September 2004 (see "Financial Condition—Cash Flows—Investing Activities," below, and Note 9).

Other Income and Expense—Net

The following table summarizes other income and expense—net by primary components for the last three years:

Thousands	2005	2004	2003
Gains from company-owned life insurance	$ 1,856	$ 2,855	$ 3,406
Allowance for funds used during construction - equity	-	708	831
Interest income	403	232	587
Other non-operating expense	(1,393)	(1,222)	(2,156)
Interest income (charges) on deferred regulatory accounts	282	74	(992)
Earnings from equity investments of Financial Corporation	57	181	474
Total other income and expense - net	$ 1,205	$ 2,828	$ 2,150

Other income and expense—net was $1.6 million lower in 2005 compared to 2004. The decrease was primarily due to lower gains from company-owned life insurance ($1.0 million), reflecting the liquidation of $17.6 million in cash surrender value of policies in 2004, and the absence of the equity component of allowance for funds used during construction ($0.7 million) reflecting lower construction work in progress balances.

Other income and expense—net improved by $0.7 million in 2004 over 2003. The increase was primarily due to reductions in interest charges on deferred regulatory account balances ($1.1 million), reflecting lower net credit balances outstanding in these accounts. This increase was partially offset by a decrease in gains from company-owned life insurance ($0.6 million) due to decreases in the market value of equity-based life insurance investments.

Interest Charges—Net of Amounts Capitalized

Interest charges—net of amounts capitalized in 2005 was $1.5 million, or 4 percent, higher than in 2004, reflecting higher balances of long-term debt outstanding during the period due to the issuance of $50 million in June 2005, and higher interest rates on short-term debt. Allowance for funds used during construction reduced interest expense by $0.5 million in 2005, compared to reductions of $1.0 million in 2004 and $0.9 million in 2003. The decrease in allowance for funds used during construction in 2005 reflects the completion in 2004 of our South Mist pipeline extension investment, which extended the pipeline from our Mist gas storage field to serve growing portions of our service area. The average interest crediting rate for allowance for funds used during construction, comprised of short-term and long-term borrowing rates, as appropriate, was 3.1 percent in 2005, 3.0 percent in 2004 and 2.3 percent in 2003.

Income Taxes

Income taxes increased $6.2 million in 2005 compared to 2004, primarily due to a combination of higher pre-tax income and a higher effective income tax rate. The increase in the effective income tax rate, from 34.4 percent in 2004 to 36.0 percent in 2005, is primarily attributable to a decrease in tax benefits resulting from a non-taxable gain on life insurance in 2004 ($0.8 million) and from other tax adjustments recorded in prior years ($0.7 million). The $3.2 million increase in income taxes in 2004 compared to 2003 also reflects higher pre-tax income and a higher effective tax rate. The effective income tax rate in 2003 was 33.7 percent. The higher rate in 2004 reflects the effect of decreased tax benefits from a non-taxable gain on Company- and trust-owned life insurance ($0.6 million), decreased tax benefits attributed to tax adjustments recorded in the prior year ($0.3 million), decreased tax benefits resulting from a taxable gain on the surrender of certain Company-owned life insurance ($0.1 million) and the expiration of a federal low-income housing tax credit ($0.1 million), partially offset by the effect of increased tax benefits from an adjustment of the Company's deferred income tax balances ($0.5 million) (see Note 8).

Redeemable Preferred Stock Dividend Requirements

There were no redeemable preferred stock dividend requirements in 2005 or 2004 due to the redemption in November 2003 of all outstanding shares of the $7.125 Series of Redeemable Preferred Stock. No shares of redeemable preferred stock were outstanding at any time during 2005 or 2004.

Financial Condition

Capital Structure

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

December 31,	2005	2004
Common stock equity	47.2%	48.7%
Long-term debt	42.0%	41.3%
Short-term debt, including current maturities of long-term debt	10.8%	10.0%
Total	100.0%	100.0%

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

Liquidity and Capital Resources

At Dec. 31, 2005, we had $7.1 million in cash and cash equivalents compared to $5.2 million at Dec. 31, 2004. Short-term liquidity is provided by cash from operations and from the sale of commercial paper notes, which are supported by committed bank lines of credit. We have available through Sept. 30, 2010 committed bank lines totaling $200 million with five commercial banks (see "Lines of Credit," below, and Note 6). Short-term debt balances typically are reduced toward the end of the winter heating season as a significant amount of our current assets, primarily accounts receivable and gas inventories, are converted into cash.

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

To provide long-term financing, we periodically issue and sell secured debt, unsecured debt, preferred stock or common stock. In April 2004, we issued $40 million of common stock and in June 2005 we issued $50 million of secured medium-term notes, leaving $110 million available for future issuance, which has previously been approved by the OPUC (see "Financing Activities," below).

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

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

Dividend Policy

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

Off-Balance Sheet Arrangements

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

Contractual Obligations

The following table shows our contractual obligations by maturity and type of obligation. We also have obligations with respect to our pension and post-retirement medical benefit plans (see Note 7).

	Payments Due in Years Ending Dec 31,						
Thousands	2006	2007	2008	2009	2010	Thereafter	Total
Commercial paper	$126,700	$ -	$ -	$ -	$ -	$ -	$ 126,700
Long-term debt	8,000	29,500	5,000	-	35,000	452,000	529,500
Interest on long-term debt	34,638	33,162	32,345	32,129	32,119	365,501	529,894
Capital leases	274	183	96	19	-	-	572
Operating leases	4,397	4,210	4,108	4,082	4,080	40,104	60,981
Gas purchase contracts[1]	505,930	273,928	250,700	123,338	61,628	129,113	1,344,637
Gas pipeline commitments	62,033	57,382	55,697	49,520	50,959	233,549	509,140
Other purchase commitments	9,888	298	-	-	-	-	10,186
Total	$751,860	$398,663	$347,946	$209,088	$183,786	$1,220,267	$3,111,610

[1] All gas purchase contracts use price formulas tied to monthly index prices. Commitment amounts are based on index prices at Dec. 31, 2005.

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

Holders of certain long-term debt have put options that, if exercised, would require repurchases of up to $20 million of principal amounts in each of 2007, 2008 and 2009. If repurchased prior to maturity, then the interest obligation shown in the above table would be reduced in future years. The interest rate on the long-term debt issues with put options range between 6.52 percent and 7.05 percent.

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

Commercial Paper

Our primary source of short-term funds is from the sale of commercial paper notes. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas inventories and accounts receivable, short-term debt may also be used to temporarily fund capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. Our commercial paper program is supported by committed bank lines of credit (see "Lines of Credit," below). We had $126.7 million in commercial paper notes outstanding at Dec. 31, 2005, compared to $102.5 million at Dec. 31, 2004.

Lines of Credit

In September 2005, we entered into agreements for unsecured lines of credit totaling $200 million with five commercial banks, replacing the previous $150 million credit facilities. The new bank lines of credit are available and committed for a term of five years from Oct. 1, 2005 to Sept. 30, 2010. Our bank lines are used primarily as back-up support for the notes payable under our commercial paper borrowing program. Commercial paper provides the liquidity to meet our working capital and external financing requirements.

Under the terms of these bank lines, we pay upfront fees and annual commitment fees but are not required to maintain compensating bank balances. The interest rates on outstanding loans, if any, under these bank lines are based on then-current market interest rates. All principal and unpaid interest under the bank lines is due and payable on Sept. 30, 2010.

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

The bank lines also require us to maintain an indebtedness to total capitalization ratio of 65 percent or less. Failure to comply with this covenant would entitle the banks to terminate their lending commitments and accelerate the maturity of all amounts outstanding. We were in compliance with this covenant at Dec. 31, 2005.

Credit Ratings

The table below summarizes our credit ratings from three rating agencies, S&P, Moody's and Fitch Ratings (Fitch).

	S&P	Moody's	Fitch
Commercial paper (short-term debt)	A-1+	P-1	F1
Senior secured (long-term debt)	AA-	A2	A+
Senior unsecured (long-term debt)	A+	A3	A
Ratings outlook	Stable	Stable	Stable

On Feb. 28, 2006, S&P raised the credit ratings on our senior secured long-term debt to "AA-" from "A+" and our senior unsecured long-term debt to "A+" from "A." S&P also raised the credit ratings on commercial paper to "A-1+" from "A-1." In June 2005, Fitch raised the credit ratings on our first mortgage bonds and secured medium-term notes to "A+" from "A", and also raised our unsecured debt rating to 'A' from 'A-'. Each of the rating agencies has assigned us an investment grade rating. These credit ratings and ratings outlook scores are dependent upon a number of factors, both qualitative and quantitative, and are subject to change at any time. The disclosure of these credit ratings is not a recommendation to buy, sell or hold our securities. Each rating should be evaluated independently of any other rating.

Optional Redemptions of Long-Term Debt and Redeemable Preferred Stock

In July 2005, we redeemed three series of maturing secured medium-term notes aggregating $15 million in principal amount. The series redeemed were the 6.34% Series B, the 6.38% Series B and the 6.45% Series B, each due in July 2005. The notes were redeemed with proceeds from the sales of $50 million in principal amount of secured medium-term notes in June 2005 (see "Cash Flows—Financing Activities," below).

In August 2005, we called for redemption all of our outstanding convertible debentures, 7-¼% Series due 2012 at 100% of their principal amount plus accrued interest to the date of redemption. During 2005, debentures with an aggregate principal amount of $4.0 million were converted into shares of common stock on or prior to the redemption date at the rate of 50.25 shares for each $1,000 principal amount of debentures and $0.5 million of debentures were redeemed.

Cash Flows

Operating Activities

Year-over-year changes in our operating cash flows are primarily affected by net income, changes in working capital requirements and other cash and non-cash adjustments to operating results. In 2005, the cash flow from net income and operating activity adjustments, excluding working capital changes, decreased by $26.7 million, primarily due to a decrease in deferred income tax benefits reflecting the expiration of higher tax benefits realized in 2004 from accelerated bonus depreciation and an increase in cash contributions to qualified pension plans, partially offset by an increase in net income and cash from deferred gas costs. In 2004, net income and operating activity adjustments, excluding working capital changes, increased cash flow by $21.3 million, but the cash flow increase was offset by increases in working capital requirements within the utility segment resulting from warmer weather, higher prices of natural gas, and the timing of customer collections, payments for natural gas purchases and deferred gas cost recoveries.

The overall change in cash flow from operating activities in 2005 compared to 2004 was a decrease of $25.8 million. The overall change in cash flow from operations was negligible in 2004 compared to 2003. The significant factors contributing to the cash flow changes between years are as follows:

2005 compared to 2004:

- an increase in net income added $7.6 million to cash flow;
- a decrease in deferred income tax expense in 2005, compared to a significant increase in 2004, decreased cash by $27.2 million, reflecting the expiration of higher tax benefits realized in 2004 from accelerated bonus depreciation;
- a small decrease in regulatory receivables in 2005, compared to a large increase in 2004 for deferred gas costs, increased cash flow by $17.8 million, reflecting deferral activity, including collections, between the two years with respect to purchased gas cost savings and off-system gas sales under our PGA tariff;
- cash contributions to our pension and postretirement benefit plans decreased cash flows by $22.7 million, primarily due to a $31 million pension contribution to our defined benefit pension plans in 2005, compared to $8.3 million in 2004;
- an increase in deferred environmental costs decreased cash by $6.9 million, reflecting an increase in cash requirements for environmental remediation work during 2005 (see "Contingent Liabilities—Environmental Matters," below);
- a larger increase in accounts receivable reduced cash flow by $11.6 million, primarily reflecting the higher gas prices and the timing of customer account collections;
- a larger increase in accrued unbilled revenue reduced cash flow by $11.8 million, reflecting a combination of higher gas prices and colder weather in December 2005 compared to December 2004;
- an increase in inventories decreased cash flow by $4.1 million, primarily reflecting injections into storage at higher gas prices;
- a decrease in income taxes receivable increased cash flow by $9.7 million; and
- an increase in accounts payable increased cash flow by $16.4 million, primarily reflecting higher gas prices at year-end 2005.

2004 compared to 2003:

- an increase in net income added $4.6 million to cash flow;
- an increase in deferred income tax expense increased cash flow by $23.0 million, reflecting higher tax benefits from accelerated bonus depreciation on large capital additions that were placed into service in 2004;
- an increase in regulatory receivables for deferred gas costs decreased cash flow by $10.2 million, reflecting different patterns of activity between the two years with respect to purchased gas cost savings and off-system gas sales under our PGA tariff;
- cash contributions to our pension and postretirement plans decreased cash flows by $8.3 million, primarily due to a cash contribution to our defined benefit pension plan, compared to no contributions in 2003 (see "Pension Cost (Income) and Funding Status," below);
- an increase in accounts receivable decreased cash flows by $9.5 million, reflecting the impact of higher rates compared to the prior year;
- an increase in other long term liabilities added $8.2 million to cash flow, reflecting an increase in accruals for unfunded liabilities for pension and post-retirement benefits and other liabilities;

- a smaller increase in accrued unbilled revenue increased cash flow by $9.7 million, reflecting higher gas prices, partially offset by lower unbilled volumes because of warmer weather, and decreases in customer usage because of higher prices;
- an increase in inventories decreased cash flow by $22.8 million, primarily reflecting higher volumes and higher unit prices on gas inventories in storage facilities;
- an increase in income taxes receivable decreased cash flow by $7.3 million; and
- a decrease in prepayments and other current assets increased cash flow by $4.4 million.

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

The Job Creation and Worker Assistance Act of 2002 combined with the Jobs and Growth Tax Relief Reconciliation Act of 2003, allowed for an additional first-year tax depreciation deduction on the adjusted basis of "qualified property" of up to 50 percent of an asset's adjusted basis. The additional first-year depreciation deduction is an acceleration of depreciation deductions that otherwise would have been taken in the later years of an asset's recovery period. The accelerated depreciation provisions provided by the acts expired Dec. 31, 2004. We realized enhanced cash flow from reduced income taxes totaling an estimated $57 million during the effective period, based on plant investments made between Sept. 11, 2001 and Dec. 31, 2004.

Investing Activities

Cash requirements for investing activities in 2005 totaled $92.0 million, down from $132.6 million in the same period of 2004. Cash requirements for the acquisition and construction of utility plant totaled $89.3 million, down from $138.3 million in the same period of 2004. The decrease in cash requirements for utility construction in 2005 reflects the completion in 2004 of our South Mist pipeline extension investment, which extended the pipeline from our Mist gas storage field to serve growing portions of our service area. The total cost of the project was approximately $108 million, which includes amounts reflected in investing activities over the past few years. The cost of service associated with the final phase of the project, net of deferred tax benefits, was included in utility customer rates beginning in the fourth quarter of 2004.

Cash requirements for investing activities in 2004 totaled $132.6 million, up from $124.8 million in 2003. Cash requirements for the acquisition and construction of utility plant totaled $138.3 million, up from $121.4 million in 2003. The increase in cash requirements for utility construction in 2004 was primarily the result of higher capital expenditures relating to the South Mist pipeline extension project ($27 million), higher system improvements and support ($12 million) and other special projects to serve new customer load or new service areas ($9 million).

Investments in our pipeline integrity management program were $6.1 million in 2005, compared to $1.6 million in 2004. These costs are estimated at approximately $50 million to $100 million over a ten-year period from 2002 through 2012 and are classified as either capital expenditures or regulatory assets. The costs are accumulated over each 12-month period ending September 30, and the costs, subject to audit, are recovered through the annual PGA based on adjustments to rate base, effective on Oct. 1 of each year. The approved accounting and rate treatment for these costs extends through Sept. 30, 2008, and may be reviewed for potential extension after that date.

Investments in non-utility property totaled $6.8 million in 2005, compared to $10.6 million in 2004 and $2.6 million in 2003. The higher investments in both 2005 and 2004 compared to 2003 were primarily for improvements to our interstate gas storage segment.

In December 2004, we received proceeds from the surrender of certain life insurance policies and proceeds from the settlement of life insurance benefits totaling $17.6 million.

During the five-year period 2006 through 2010, utility construction expenditures are estimated at between $500 and $600 million. The level of capital expenditures over the next five years reflects continued customer growth and system improvement projects, resulting in part from requirements under the Pipeline Safety Improvement Act of 2002. Most of the required funds are expected to be internally generated over the five-year period and any remaining funding will be through long-term debt, with short-term debt providing liquidity and bridge financing.

Our utility and non-utility capital expenditures in 2006 are estimated to total $104 million, including $32 million for customer growth, $19 million for system improvements, $12 million for equipment, facilities and information technology, $7 million for pipeline integrity costs, $10 million for an automated meter reading project, $2 million for utility and non-utility storage, and $22 million for construction overhead.

In December 2003, the U.S. Department of Transportation's Office of Pipeline Safety (now the Pipeline Hazardous Materials Safety Administration) issued a rule that specifies the detailed requirements for transmission pipeline integrity management plans as mandated by the Pipeline Safety Act. The Pipeline Safety Act requires operators of gas transmission pipelines to identify lines located in high consequence areas and to develop programs to periodically inspect the integrity of the pipelines and make repairs or replacements as necessary to ensure the ongoing integrity of the pipelines. The legislation requires us to inspect the 50 percent highest risk pipelines located in high consequence areas within the first five years, and to inspect the remaining covered pipelines within 10 years of the date of the enactment. The Pipeline Safety Act also requires re-inspections of the covered pipelines every seven years from the date of the previous inspection for the life of the pipelines.

Financing Activities

Cash provided by financing activities in 2005 totaled $14.8 million, compared to $28.3 million in 2004. Factors contributing to the $13.4 million decrease were the redemption of long term debt and convertible debentures ($15.5 million), the increased repurchases of common stock in 2005 ($14.9 million) and the lower amount of equity financing in 2005 ($39.1 million), partially offset by the issuance of $50 million of secured medium-term notes during 2005 and the increase in short-term debt ($6.9 million).

Cash provided by financing activities in 2004 totaled $28.3 million, compared to $16.9 million in 2003. Factors contributing to the $11.3 million increase were the net proceeds from a common stock offering in April 2004 ($38.5 million) (see below), combined with the redemption of the $7.125 series of preferred stock ($8.4 million) in 2003, offset by an increase in long-term debt balances ($35.0 million) in 2003.

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

In 2003, we sold $90 million of secured, Series B medium-term notes and used the proceeds to redeem long-term debt ($55 million), to provide cash for investments in utility plant and to reduce short-term borrowings.

In April 2004, we issued and sold 1,290,000 shares of our common stock in an underwritten public offering, and used the net proceeds of $38.5 million from the offering to reduce short-term indebtedness by about $29 million and to fund, in part, our utility construction program.

In 2000, we commenced a program to repurchase up to 2 million shares, or up to $35 million in value, of our common stock through a repurchase program that has been extended through May 2006. The purchases are made in the open market or through privately negotiated transactions. In 2005, we purchased 410,200 shares at a cost of $14.9 million. No shares were purchased pursuant to the program in 2004. Since the program's inception, we have repurchased 765,600 shares of common stock at a total cost of $23.1 million (see Part II, Item 5, "Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" above).

Pension Cost (Income) and Funding Status

Net periodic pension cost is determined in accordance with SFAS No. 87, "Employers' Accounting for Pensions" (see "Application of Critical Accounting Policies—Accounting for Pensions," above). The annual pension cost or income is allocated between operations and maintenance expense and construction overhead.

Net periodic pension cost for our two qualified defined benefit pension plans totaled $6.9 million in 2005, an increase of $0.3 million over net periodic pension cost for these plans of $6.6 million in 2004. The increased net periodic pension cost was primarily due to a lower discount rate (6.00 percent in 2005 compared to 6.25 percent in 2004), partially offset by earnings on additional cash contributions to the plans.

We make contributions to our qualified defined benefit pension plans based on actuarial assumptions and estimates, tax regulations and funding requirements under federal law. Generally, it is our policy to contribute at least the minimum amount required by the Employee Retirement Income Security Act of 1974. It is also our intent to contribute additional amounts as are sufficient on an actuarial basis to maintain funding targets and provide for the payment of future benefits under the plans.

During 2005, we contributed $31 million to our two qualified defined benefit plans. Although we were not required to make additional cash contributions in 2005 based on minimum funding requirements, we contributed $20 million in September 2005 and an additional $11 million in December 2005 based on increases in the benefit obligations. During 2004, we contributed $8.3 million, of which $2.9 million represented the minimum required funding.

The fair market value of the two plans' assets increased to $219 million at Dec. 31, 2005, up from $187 million at Dec. 31, 2004. The increase included $13.5 million in investment gains and employer contributions of $31 million, which were offset in part by $11.8 million in withdrawals to pay benefits and $0.9 million in eligible expenses of the two plans. The present value of benefit obligations under the two plans increased from an estimated $209 million to $254 million during 2005, reflecting the adoption of new mortality assumptions for the plans and the lower discount rate referred to above. The two qualified deferred benefit pension plans were under funded in aggregate by approximately $36 million at Dec. 31, 2005.

Net periodic pension cost for the plans was $6.6 million in 2004, compared to $6.2 million in 2003. The increased net periodic pension cost in 2004 was primarily due to the use of a lower discount rate (6.25 percent in 2004 compared to 6.75 percent in 2003), which had the effect of increasing the two plans' accumulated benefit obligations. During 2003, no contributions were made to the qualified defined benefit pension plans.

At Dec. 31, 2004, the fair market value of the qualified plans' assets totaled $187 million, up from $168 million at Dec. 31, 2003. The increase included $22.5 million in investment gains and employer contributions of $8.3 million, which were offset in part by $11.2 million in withdrawals to pay benefits and $1.1 million in eligible expenses of the two plans. The present value of benefit obligations under the two plans increased from an estimated $192 million to $209 million during 2004. The two plans were under funded in aggregate by about $22 million at Dec. 31, 2004.

Despite the increase in net periodic pension cost and the current under-funded status of the plans, we believe the plans to be well-funded and that we will be able to continue to maintain appropriate funding levels. We do not expect our current or future cash contribution requirements to the two plans to have a material adverse effect on our liquidity or financial condition (see Note 7).

Ratios of Earnings to Fixed Charges

For the years ended Dec. 31, 2005, 2004 and 2003, our ratios of earnings to fixed charges, computed using the Securities and Exchange Commission method, were 3.32, 3.02 and 2.84, respectively. For this purpose, earnings consist of net income before taxes plus fixed charges, and fixed charges consist of interest on all indebtedness, the amortization of debt expense and discount or premium and the estimated interest portion of rentals charged to income.

Contingent Liabilities

Loss contingencies are recorded as liabilities when it is probable that a liability has been incurred and the amount of the loss is reasonably estimable in accordance with SFAS No. 5, "Accounting for Contingencies," (see "Applications of Critical Accounting Policies of Estimates—Contingencies," above). At Dec. 31, 2005, a cumulative $18.8 million in environmental costs has been recorded as a regulatory asset, including $12.4 million of costs paid to-date and $6.4 million of estimated accrued future environmental costs. If it is determined that both the insurance recovery and future customer rate recovery of such costs is not probable, then the costs will be charged to expense in the period such determination is made (see Note 12).

Industrial Customers Switching from Transportation to Sales Service

High natural gas prices in the third quarter of 2005 resulted in some of the utility's large industrial transportation customers electing to receive gas commodity under sales service instead of arranging for their own supplies through independent third parties. Since these customers were electing to transfer to sales service after commodity rates were set in the annual PGA, the relevant tariff required us to charge these customers the incremental cost of gas supply incurred to serve them. In October 2005, we notified these customers that they would be charged incremental gas supply costs. Certain of these customers notified us that they expected to be charged gas costs at our weighted average cost of gas price.

We have worked with the OPUC, WUTC and these industrial customers to reach settlements and have resolved the matter with all but one of the customers. We filed the settlement agreements with the OPUC and WUTC. In the fourth quarter of 2005, we recorded a charge of $2.8 million related to obligations under these settlement agreements and the related anticipated future legal and other expenses.

Two formal complaints filed with the OPUC in connection with this matter have been dismissed by the OPUC. On Dec. 6, 2005, the OPUC opened an investigation to determine whether we had provided adequate information about rates to the industrial customers. On Feb. 1, 2006, we filed a motion with the OPUC to close the investigation based on our settlement with 14 of the 15 Oregon industrial customers. On Feb. 3, 2006, an administrative law judge for the OPUC held a pre-hearing conference in the investigation, at which both the Northwest Industrial Gas Users and the OPUC Staff supported our motion. The administrative law judge has postponed all further action in the investigation until a ruling on our motion.

On Jan. 5, 2006, we filed a Complaint for Declaratory Judgment in Multnomah County, Oregon, against Georgia-Pacific Corporation seeking a declaration, among other things, that the utility and Georgia-Pacific are bound by the terms of the tariff. On Feb. 3, 2006, Georgia-Pacific filed a complaint against us in the United States District Court alleging breach of contract, duty of good faith and fair dealing, promissory estoppel, fraudulent misrepresentation and violations of certain Oregon statutes. When Georgia-Pacific responded by filing the federal lawsuit described above, and removing the declaratory judgment suit to federal court on Feb. 2, 2006, we voluntarily dismissed our suit for declaratory judgment in state court, and now all matters between the parties are before the federal court. We will vigorously contest the claims asserted by Georgia-Pacific. We do not expect the final outcome of this litigation to have a material effect on our results of operations or financial condition.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Supply Risk

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

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

Commodity Price Risk

Natural gas commodity prices are subject to fluctuations due to unpredictable factors including weather, pipeline transportation congestion and other factors that affect short-term supply and demand. Commodity-price swap and call option contracts (financial hedge contracts) are used to convert certain natural gas supply contracts from floating prices to fixed prices. These financial hedge contracts are generally included in our annual PGA filing, subject to a prudency review. At Dec. 31, 2005 and 2004, notional amounts under these commodity swap and call option contracts totaled $470.5 million and $413.0 million, respectively. At Dec. 31, 2005, five of these financial hedge contracts have maturities in 2007 and one contract has a maturity in 2008. If all of the commodity-price swap and call option contracts had been settled on Dec. 31, 2005, a regulatory gain of $175.7 million would have been realized and deferred (see Note 11). We monitor the liquidity of our financial derivative contracts. Based on the existing open interest in the contracts held, we believe existing contracts to be liquid. All of our financial derivative contracts settle within the next three years. The $175.7 million unrealized gain is an estimate of future cash flows that are expected to be realized as follows: $132.6 million in 2006, $35.9 million in 2007 and $7.2 million in 2008. The amount realized will change based on market prices at the time contract settlements are fixed.

Commodity Supply Risk with Unaffiliated Energy Marketing Company

In the first quarter of 2005, we entered into a series of exchange transactions with an unaffiliated energy marketing company which resulted in our accounting for forward gas purchase contracts as derivative instruments under SFAS No. 133. SFAS No. 133 requires that derivative instruments be recorded on the balance sheet at fair value. The mark-to-market adjustment at Dec. 31, 2005 is an unrealized loss of $4.1 million which is recorded as a liability with an offsetting entry to a regulatory asset account based on regulatory deferral accounting treatment under SFAS No. 71. Prior to the first quarter of 2005, our forward gas supply contracts were excluded from the provisions of SFAS No. 133 under the normal purchase and normal sale exception that is allowed for contracts that are probable of delivery in the normal course of business. These exchange transactions are intended and designed to reduce commodity prices, with the derivatives decreasing our net exposures to market risk. These derivatives are used for managing business risks and not for trading purposes.

In the exchange transactions referred to above, we continue to receive the same quantities of physical deliveries of natural gas volumes at the entry point into our distribution system, while the unaffiliated energy marketing company seeks to use the equivalent physical commodity volumes at an upstream delivery point. Under the optimization agreement with this company, we receive a fixed fee plus a share of any gains above the fixed fee. Our exchange transaction is consistent with our policies on physical gas purchases and derivative instruments, which govern the use of commodity supply contracts and financial derivatives in order to manage our commodity supply and related price risk. These policies provide for the use of only those contracts, volumes and instrument types that are needed in the normal course of business, that help to manage gas supply costs and that have a close volume or price correlation to our assets, liabilities or forecasted transactions, thereby ensuring that such instruments will be used for hedging business risks and not for trading purposes.

Foreign Currency Risk

The costs of certain natural gas commodity supplies and certain pipeline services purchased from Canadian suppliers are subject to changes in the value of the Canadian currency in relation to the U.S. currency. Foreign currency forward contracts are used to hedge against fluctuations in exchange rates with respect to the purchases of natural gas from Canadian suppliers. At Dec. 31, 2005 and 2004, notional amounts under foreign currency forward contracts totaled $19.9 million and $14.5 million, respectively. As of Dec. 31, 2005, no foreign currency forward contracts extended beyond Dec. 31, 2006. If all of the foreign currency forward contracts had been settled on Dec. 31, 2005, a gain of $0.2 million would have been realized (see Note 11).

Credit Risk

Credit exposure to suppliers. Certain suppliers that sell us gas have either relatively low credit ratings or are not rated by major credit rating agencies. To manage this supply risk, we purchase gas from a number of different suppliers, with no single supplier accounting for more than 20 percent of our total purchases for a given monthly period. We evaluate suppliers' creditworthiness and maintain the ability to require additional financial assurances, including deposits, letters of credit or surety bonds in case a supplier defaults. In the event of a supplier's failure to deliver contracted volumes of gas, the regulated utility would need to replace those volumes at prevailing market prices, which may be higher or lower than the original transaction prices. We believe these costs would be subject to the PGA sharing mechanism discussed above. Since most of our commodity supply contracts are priced at the monthly market index price, and we have significant storage flexibility, we believe that it is unlikely that a supplier default would have a materially adverse impact on our financial condition or results of operations.

Credit exposure to financial derivative counterparties. Based on estimated fair value, our credit exposure to financial derivative counterparties relating to commodity swap and call option contracts was $175.7 million at Dec. 31, 2005. Our Derivatives Policy requires counterparties to have a minimum 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. There were no credit rating downgrades for any of our counterparties during 2005.

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

	Financial Derivative Exposure by Credit Rating Unrealized Fair Value Gain	
Thousands	Dec. 31, 2005	Dec. 31, 2004
AA/Aa	$172,315	$ 8,461
BBB/Baa	3,346	1,985
Total	$175,661	$10,446

Credit exposure to customers. Increases in the market price of natural gas are expected to increase our credit exposure to customers. Also, higher prices have resulted in some of our largest industrial customers changing from transportation service to sales service. Under transportation service, the customer is purchasing its commodity supplies from an independent third party, with the utility only providing the transportation service for delivery of that gas to the customer's premise. Under sales service, the customer is purchasing both its gas commodity supply and transportation service from us. With higher natural gas commodity prices, our credit exposure to large industrial sales customers is expected to increase significantly. We monitor and manage the credit exposure of our industrial sales customers through credit policies and procedures, which are designed to reduce credit risk. These policies and procedures include an ongoing review of credit risks, including changes in the services provided to industrial customers as well as changes in market conditions and customers' credit quality. Changes in credit risk may require us to obtain additional assurance, such as deposits, letters of credit, guarantees and prepayments to reduce our credit exposure.

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

Weather Risk

We are exposed to weather risk primarily from our regulated utility business. A large percentage of our utility margin is volume driven, and current rates are based on an assumption of average weather. In 2003, the OPUC approved a weather normalization mechanism for residential and commercial customers. This mechanism affects customer bills between Nov. 15 through May 15 of each winter heating season, increasing or decreasing the margin component of customers' rates to reflect "average" weather using the 25-year average temperature for each day of the billing period. The mechanism is intended to stabilize the recovery of our utility's fixed costs and reduce fluctuations in customers' bills due to colder or warmer than average weather. Customers in Oregon are allowed to opt out of the weather normalization mechanism. As of Dec. 31, 2005, about 9 percent of our Oregon customers had opted out. In addition to the Oregon customers opting out, our Washington residential and commercial customers account for approximately 10 percent of our total customer base and are not covered by weather normalization. The combination of Oregon and Washington customers not covered by weather normalization mechanism is less than 20 percent of all residential and commercial customers.

Interest Rate Risk

We are exposed to interest-rate risk associated with new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. Interest rate risk is managed through the issuance of fixed-rate debt with varying maturities and, if permitted, the reduction of debt through optional redemption when interest rates are favorable. At Dec. 31, 2005 and 2004, we had no variable-rate long-term debt and no derivative financial instruments to hedge interest rates. Holders of certain long- term debt have put options that, if exercised, would accelerate maturities by $20 million in each of 2007, 2008 and 2009.

Forward-Looking Statements

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

- prevailing state and federal governmental policies and regulatory actions, including those of the OPUC and the WUTC, with respect to allowed rates of return, industry and rate structure, purchased gas cost and investment recovery, acquisitions and dispositions of assets and facilities, operation and construction of plant facilities, present or prospective wholesale and retail competition, changes in tax laws and policies and changes in and compliance with environmental and safety laws, regulations, policies and orders, and laws, regulations and orders with respect to the maintenance of pipeline integrity;

- adoption and implementation by the OPUC of rules interpreting recent Oregon legislation intended to ensure that utilities do not collect in rates more income taxes than they actually pay to government entities;
- weather conditions and other natural phenomena, including earthquakes or other geohazard events;
- unanticipated population growth or decline, and changes in market demand caused by changes in demographic or customer consumption patterns;
- competition for retail and wholesale customers;
- market conditions and pricing of natural gas relative to other energy sources;
- risks relating to the creditworthiness of customers, suppliers and derivative counterparties;
- risks relating to dependence on a single pipeline transportation provider for natural gas supply;
- risks relating to property damage associated with a pipeline safety incident, as well as risks resulting from uninsured damage to our property, intentional or otherwise;
- unanticipated changes that may affect our liquidity or access to capital markets;
- our ability to maintain effective internal controls over financial reporting in compliance with Section 404 of the Sarbanes-Oxley Act of 2002;
- unanticipated changes in interest or foreign currency exchange rates or in rates of inflation;
- economic factors that could cause a severe downturn in certain key industries, thus affecting demand for natural gas;
- unanticipated changes in operating expenses and capital expenditures;
- changes in estimates of potential liabilities relating to environmental contingencies;
- unanticipated changes in future liabilities relating to employee benefit plans, including changes in key assumptions;
- capital market conditions, including their effect on pension and other postretirement benefit costs;
- potential inability to obtain permits, rights of way, easements, leases or other interests or other necessary authority to construct pipelines, develop storage or complete other system expansions; and
- legal and administrative proceedings and settlements.

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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Supplemental Schedules Omitted

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

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

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

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

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

Management assessed the effectiveness of NW Natural's internal control over financial reporting as of Dec. 31, 2005. In making this assessment, management used the framework set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework.*

Based on our assessment and those criteria, management has concluded that NW Natural maintained effective internal control over financial reporting as of Dec. 31, 2005.

Management's assessment of the effectiveness of internal control over financial reporting as of Dec. 31, 2005 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears in this annual report.

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

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

March 1, 2006

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have completed integrated audits of Northwest Natural Gas Company's 2005 and 2004 consolidated financial statements and of its internal control over financial reporting as of December 31, 2005 and 2004, and an audit of its 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

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, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005 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. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes 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. We believe that our audits provide a reasonable basis for our opinion.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Controls Over Financial Reporting appearing under Item 8, that the Company maintained effective internal control over financial reporting as of December 31, 2005 based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control—Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides 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 the board of directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

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

PricewaterhouseCoopers LLP
Portland, Oregon
February 28, 2006

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF INCOME

Thousands, except per share amounts (year ended December 31)	2005	2004	2003
Operating revenues:			
Gross operating revenues	$910,486	$707,604	$611,256
Cost of sales	563,860	399,244	323,190
Revenue taxes	21,633	16,865	14,650
Net operating revenues	324,993	291,495	273,416
Operating expenses:			
Operations and maintenance	113,216	102,155	96,420
General taxes	23,185	21,943	20,475
Depreciation and amortization	61,645	57,371	54,249
Total operating expenses	198,046	181,469	171,144
Income from operations	126,947	110,026	102,272
Other income and expense - net	1,205	2,828	2,150
Interest charges - net of amounts capitalized	37,283	35,751	35,099
Income before income taxes	90,869	77,103	69,323
Income tax expense	32,720	26,531	23,340
Net income	58,149	50,572	45,983
Redeemable preferred stock dividend requirements	-	-	294
Earnings applicable to common stock	$ 58,149	$ 50,572	$ 45,689
Average common shares outstanding:			
Basic	27,564	27,016	25,741
Diluted	27,621	27,283	26,061
Earnings per share of common stock:			
Basic	$ 2.11	$ 1.87	$ 1.77
Diluted	$ 2.11	$ 1.86	$ 1.76

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2005	2004
Assets:		
Plant and property:		
Utility plant	$1,875,444	$1,794,972
Less accumulated depreciation	536,867	505,286
Utility plant - net	1,338,577	1,289,686
Non-utility property	40,836	33,963
Less accumulated depreciation and amortization	5,990	5,244
Non-utility property - net	34,846	28,719
Total plant and property	1,373,423	1,318,405
Other investments	58,451	60,618
Current assets:		
Cash and cash equivalents	7,143	5,248
Accounts receivable	84,418	60,634
Accrued unbilled revenue	81,512	64,401
Allowance for uncollectible accounts	(3,067)	(2,434)
Gas inventory	77,256	58,015
Materials and supplies inventory	8,905	8,462
Income taxes receivable	13,234	15,970
Prepayments and other current assets	54,309	26,821
Total current assets	323,710	237,117
Regulatory assets:		
Income tax asset	65,843	64,734
Deferred environmental costs	18,880	6,325
Deferred gas costs receivable	6,974	9,551
Unamortized costs on debt redemptions	6,881	7,332
Other	-	3,321
Total regulatory assets	98,578	91,263
Other assets:		
Fair value of non-trading derivatives	178,653	16,399
Other	9,216	8,393
Total other assets	187,869	24,792
Total assets	$2,042,031	$1,732,195

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

Thousands (December 31)	2005	2004
Capitalization and liabilities:		
Capitalization:		
Common stock	$ 87,334	$ 87,231
Premium on common stock	296,471	300,034
Earnings invested in the business	205,687	183,932
Unearned stock compensation	(650)	(862)
Accumulated other comprehensive income (loss)	(1,911)	(1,818)
Total common stock equity	586,931	568,517
Long-term debt	521,500	484,027
Total capitalization	1,108,431	1,052,544
Current liabilities:		
Notes payable	126,700	102,500
Long-term debt due within one year	8,000	15,000
Accounts payable	135,287	102,478
Taxes accrued	12,725	10,242
Interest accrued	2,918	2,897
Other current and accrued liabilities	40,935	34,168
Total current liabilities	326,565	267,285
Regulatory liabilities:		
Accrued asset removal costs	169,927	153,258
Unrealized gain on non-trading derivatives, net	171,777	10,912
Customer advances	1,847	1,529
Other	661	-
Total regulatory liabilities	344,212	165,699
Other liabilities:		
Deferred income taxes	222,331	211,080
Deferred investment tax credits	5,069	5,660
Fair value of non-trading derivatives	6,876	5,487
Other	28,547	24,440
Total other liabilities	262,823	246,667
Commitments and contingencies (see Note 12)	-	-
Total capitalization and liabilities	$2,042,031	$1,732,195

See Notes to Consolidated Financial Statements.

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

Thousands	Common Stock And Premium	Earnings Invested in the Business	Unearned Stock Compensation	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Comprehensive Income
Balance at Dec. 31, 2002	$329,051	$157,136	$(711)	$(3,084)	$482,392	
Net Income	-	45,983	-	-	45,983	$45,983
Minimum pension liability adjustment - net of tax	-	-	-	2,068	2,068	2,068
Purchases of restricted stock	-	-	(328)	-	(328)	
Restricted stock amortizations	-	-	310	-	310	
Cash dividends paid:						
Redeemable preferred stock	-	(392)	-	-	(392)	
Common stock	-	(32,655)	-	-	(32,655)	
Tax benefits from employee stock option plan	401	-	-	-	401	
Issuance of common stock	7,930	-	-	-	7,930	
Convertible debentures	626	-	-	-	626	
Common stock expense	-	(19)	-	-	(19)	
Balance at Dec. 31, 2003	338,008	170,053	(729)	(1,016)	506,316	$48,051
Net Income	-	50,572	-	-	50,572	$50,572
Minimum pension liability adjustment - net of tax	-	-	-	(802)	(802)	(802)
Purchases of restricted stock	(55)	(51)	(431)	-	(537)	
Restricted stock amortizations	-	-	298	-	298	
Cash dividends paid:						
Common stock	-	(35,105)	-	-	(35,105)	
Tax benefits from employee stock option plan	872	-	-	-	872	
Issuance of common stock	47,148	-	-	-	47,148	
Convertible debentures	1,292	-	-	-	1,292	
Common stock expense	-	(1,537)	-	-	(1,537)	
Balance at Dec. 31, 2004	387,265	183,932	(862)	(1,818)	568,517	$49,770
Net Income	-	58,149	-	-	58,149	$58,149
Minimum pension liability adjustment - net of tax	-	-	-	(93)	(93)	(93)
Restricted stock amortizations	-	-	212	-	212	
Cash dividends paid:						
Common stock	-	(36,376)	-	-	(36,376)	
Tax benefits from employee stock option plan	220	-	-	-	220	
Issuance of common stock	7,266	-	-	-	7,266	
Common stock repurchased	(14,945)	-	-	-	(14,945)	
Convertible debentures	3,999	-	-	-	3,999	
Common stock expense	-	(18)	-	-	(18)	
Balance at Dec. 31, 2005	$383,805	$205,687	$(650)	$(1,911)	$586,931	$58,056

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

Thousands (year ended December 31)	2005	2004	2003
Operating activities:			
Net income	$ 58,149	$ 50,572	$ 45,983
Adjustments to reconcile net income to cash provided by operations:			
Depreciation and amortization	61,645	57,371	54,249
Deferred income taxes and investment tax credits	9,551	36,713	13,712
Undistributed earnings from equity investments	(57)	(181)	(474)
Allowance for funds used during construction	(520)	(1,690)	(1,734)
Deferred gas costs - net	2,577	(15,178)	(5,008)
Contributions to qualified defined benefit pension plans	(31,000)	(8,261)	-
Non-cash expenses related to qualified defined benefit pension plans	4,532	4,322	3,935
Deferred environmental costs	(9,132)	(2,215)	(1,385)
Income from investment in life insurance	(1,873)	(2,855)	(3,406)
Other	3,856	5,781	(2,835)
Changes in working capital:			
Accounts receivable - net	(23,151)	(11,593)	(2,135)
Accrued unbilled revenue - net	(17,111)	(5,292)	(15,040)
Inventories of gas, materials and supplies	(19,684)	(15,618)	7,171
Income taxes receivable	2,736	(6,984)	266
Prepayments and other current assets	(3,439)	245	(4,129)
Accounts payable	32,809	16,449	11,593
Accrued interest and taxes	2,504	1,536	879
Minimum pension liability adjustment	(93)	(802)	2,068
Other current and accrued liabilities	6,767	2,579	1,544
Cash provided by operating activities	79,066	104,899	105,254
Investing activities:			
Investment in utility plant	(89,259)	(138,347)	(121,411)
Investment in non-utility property	(6,842)	(10,568)	(2,563)
Proceeds from sale of non-utility investments	3,001	-	-
Proceeds from (investment in) life insurance	296	17,575	(1,387)
Other	796	(1,291)	560
Cash used in investing activities	(92,008)	(132,631)	(124,801)
Financing activities:			
Common stock issued, net of expenses	7,486	46,616	8,330
Common stock purchased	(14,945)	(537)	(328)
Redeemable preferred stock retired	-	-	(8,428)
Long-term debt issued	50,000	-	90,000
Long-term debt redeemed	(15,528)	-	(55,000)
Change in short-term debt	24,200	17,300	15,398
Cash dividend payments:			
Redeemable preferred stock	-	-	(392)
Common stock	(36,376)	(35,105)	(32,655)
Cash provided by financing activities	14,837	28,274	16,925
Increase (decrease) in cash and cash equivalents	1,895	542	(2,622)
Cash and cash equivalents - beginning of period	5,248	4,706	7,328
Cash and cash equivalents - end of period	$ 7,143	$ 5,248	$ 4,706
Supplemental disclosure of cash flow information:			
Interest paid	$ 36,974	$ 36,061	$ 35,210
Income taxes paid	$ 28,479	$ 2,500	$ 11,814
Supplemental disclosure of non-cash financing activities:			
Conversions to common stock:			
7 ¼% Series of Convertible Debentures	$ 3,999	$ 1,292	$ 626

See Notes to Consolidated Financial Statements

NORTHWEST NATURAL GAS COMPANY
CONSOLIDATED STATEMENTS OF CAPITALIZATION

Thousands (December 31)	2005		2004	
Common stock equity:				
Common stock	$ 87,334		$ 87,231	
Premium on common stock	296,471		300,034	
Earnings invested in the business	205,687		183,932	
Unearned compensation	(650)		(862)	
Accumulated other comprehensive income (loss)	(1,911)		(1,818)	
Total common stock equity	586,931	53%	568,517	54%
Long-term debt:				
Medium-Term Notes				
First Mortgage Bonds:				
6.340% Series B due 2005	-		5,000	
6.380% Series B due 2005	-		5,000	
6.450% Series B due 2005	-		5,000	
6.050% Series B due 2006	8,000		8,000	
6.310% Series B due 2007	20,000		20,000	
6.800% Series B due 2007	9,500		9,500	
6.500% Series B due 2008	5,000		5,000	
4.110% Series B due 2010	10,000		10,000	
7.450% Series B due 2010	25,000		25,000	
6.665% Series B due 2011	10,000		10,000	
7.130% Series B due 2012	40,000		40,000	
8.260% Series B due 2014	10,000		10,000	
4.700% Series B due 2015	40,000		-	
7.000% Series B due 2017	40,000		40,000	
6.600% Series B due 2018	22,000		22,000	
8.310% Series B due 2019	10,000		10,000	
7.630% Series B due 2019	20,000		20,000	
9.050% Series A due 2021	10,000		10,000	
5.620% Series B due 2023	40,000		40,000	
7.720% Series B due 2025	20,000		20,000	
6.520% Series B due 2025	10,000		10,000	
7.050% Series B due 2026	20,000		20,000	
7.000% Series B due 2027	20,000		20,000	
6.650% Series B due 2027	20,000		20,000	
6.650% Series B due 2028	10,000		10,000	
7.740% Series B due 2030	20,000		20,000	
7.850% Series B due 2030	10,000		10,000	
5.820% Series B due 2032	30,000		30,000	
5.660% Series B due 2033	40,000		40,000	
5.250% Series B due 2035	10,000		-	
Convertible Debentures				
7 1/4% Series due 2012	-		4,527	
	529,500		499,027	
Less long-term debt due within one year	8,000		15,000	
Total long-term debt	521,500	47%	484,027	46%
Total capitalization	$1,108,431	100%	$1,052,544	100%

See Notes to Consolidated Financial Statements.

NORTHWEST NATURAL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Organization and Principles of Consolidation

The consolidated financial statements include the accounts of Northwest Natural Gas Company (NW Natural), a regulated utility, and its non-regulated wholly-owned subsidiary business, NNG Financial Corporation (Financial Corporation).

Together these businesses are referred to herein as the "Company." In this report, the term "utility" is used to describe the regulated gas distribution business of the Company and the term "non-utility" is used to describe the interstate gas storage business and other non-regulated activities (see Note 2). Intercompany accounts and transactions have been eliminated.

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

Certain amounts from prior years have been reclassified to conform, for comparison purposes, with the current financial statement presentation. The current year's presentation of the Consolidated Statements of Income includes the reclassification of revenue taxes as a component of net operating revenues. Revenue taxes are expenses primarily related to the utility's franchise agreements and are based on gross operating revenues. Since revenue taxes are a direct cost of utility sales, the financial statement classification was changed to improve the presentation of net operating revenues and operating expenses. In prior years, revenue taxes were included under operating expenses as part of other taxes. The reclassifications had no impact on prior years' income from operations or consolidated net income.

Use of Estimates

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

Industry Regulation

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

In applying SFAS No. 71, NW Natural capitalizes certain costs and revenues as regulatory assets and liabilities pursuant to orders of the OPUC or WUTC in general rate or expense deferral proceedings, to provide for recovery of revenues or expenses from, or refunds to, utility customers in future periods, including a return or a carrying charge.

At Dec. 31, 2005 and 2004, the amounts deferred as regulatory assets and liabilities were as follows:

	Dec. 31,	
Thousands	2005	2004
Deferred regulatory assets	$ 98,578	$ 91,263
Deferred regulatory liabilities	(174,285)	(12,441)
Accumulated removal costs	(169,927)	(153,258)
Net deferred assets (liabilities)	$(245,634)	$ (74,436)

NW Natural believes that continued application of SFAS No. 71 for regulated activities is appropriate and consistent with the current regulatory environment, and that all regulated assets and liabilities at Dec. 31, 2005 and 2004 are recoverable or refundable through future utility rates. NW Natural also believes that it will continue to be able to earn a reasonable rate of return or a carrying charge on regulated assets, net of regulatory liabilities. If NW Natural should determine that all or a portion of these regulatory assets or liabilities no longer meet the criteria for continued application of SFAS No. 71, then it would be required to write off the net unrecoverable balances against earnings.

New Accounting Standards

Adopted Standards

Nonmonetary Transactions. In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 153, "Exchanges of Nonmonetary Assets—An Amendment of APB Opinion No. 29, Accounting for Nonmonetary Transactions," which redefines the types of non-monetary exchanges that require fair value measurement. The Company is required to adopt SFAS No. 153 for nonmonetary transactions entered into after June 30, 2005. Adoption of this new standard did not have a material impact on the Company's financial condition or results of operations.

Conditional Asset Retirement Obligations. In March 2005, the FASB issued FASB Interpretation No. (FIN) 47, "Accounting for Conditional Asset Retirement Obligations, an interpretation of SFAS No. 143." FIN 47 clarifies that an entity is required to recognize a liability for a legal obligation to perform an asset retirement activity if the fair value can be reasonably estimated even though the timing and/or method of settlement are conditional on a future event. FIN 47 is required to be adopted for annual reporting periods ending after Dec. 15, 2005. The Company has evaluated all potential conditional asset retirement obligations and has concluded that the Company's only estimable conditional asset retirement obligation as defined in FIN 47 is the purging and sealing of pipe greater than 4 inches in diameter. Adoption of the new standard did not have a material impact on the Company's financial condition or results of operations.

Recent Accounting Pronouncements

Inventory Costs. In November 2004, the FASB issued SFAS No. 151, "Inventory Costs, an amendment of ARB No. 43, Chapter 4." SFAS No. 151 amends the guidance on inventory pricing to require that abnormal amounts of idle facility expense, freight, handling costs and wasted material be charged to current period expense rather than capitalized as inventory costs.

SFAS No. 151 is effective for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company is evaluating the effect of the adoption and implementation of SFAS No. 151, which is not expected to have a material impact upon the Company's financial condition, results of operations or cash flows.

Share Based Payments. In December 2004, the FASB issued SFAS No. 123 (revised 2004), "Share Based Payments" (SFAS No. 123R), that requires companies to expense the fair value of employee stock options and similar awards. Under SFAS No. 123R, share based payment awards will be measured at fair value on the date of grant based on the estimated number of awards expected to vest. The estimated fair value will be recognized as compensation expense over the vesting period during which an employee is required to provide service in exchange for the award. The expense would be adjusted for actual forfeitures that occur before vesting, but would not be adjusted for awards that expire or terminate after vesting. The Company is evaluating different option-pricing models to determine the most appropriate measure of fair value under the new standard. Estimated fair value and compensation expense are currently calculated using the Black-Scholes option pricing model, and its corresponding impact on the financial statements is provided in Note 4 below. The Company is required to adopt SFAS No. 123R in the first quarter of 2006. SFAS No. 123R permits the use of either the modified retrospective or the modified prospective method of adoption. The Company has elected to use the modified prospective method for adopting this standard. Under this method, the Company will recognize the fair value of all share-based awards as compensation expense for all awards granted after Jan. 1, 2006 and any unvested awards previously granted and outstanding as of Jan. 1, 2006. The Company is evaluating the effect of the adoption and implementation of SFAS No. 123R, which is not expected to have a material impact on the Company's financial condition, results of operations or cash flows.

Accounting for Changes and Error Corrections. In May 2005, the FASB issued SFAS No. 154, "Accounting for Changes and Error Corrections—a replacement of APB Opinion No. 20 and FASB Statement No. 3," which provides guidance on the accounting for and reporting of accounting changes and error corrections. The statement requires retrospective application to prior periods' financial statements of changes in accounting principles, unless it is impracticable to determine the period-specific effects or the cumulative effect of the change. The guidance provided in Accounting Principles Board (APB) Opinion No. 20 for reporting the correction of an error in previously issued financial statements remains unchanged and requires the restatement of previously issued financial statements. SFAS No. 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after Dec. 15, 2005.

Purchases and Sales of Inventory with the Same Counterparty. In September 2005, the FASB's Emerging Issues Task Force (EITF) reached a final consensus on Issue 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty." EITF 04-13 requires that two or more legally separate exchange transactions with the same counterparty be combined and considered a single arrangement for purposes of applying APB Opinion No. 29, "Accounting for Nonmonetary Transactions," when the transactions are entered into in contemplation of one another. EITF 04-13 is effective for new arrangements entered into, or modifications or renewals of existing arrangements, in interim or annual periods beginning after March 15, 2006. The Company is evaluating the effect of the adoption of EITF 04-13, which is not expected to have a material impact on the Company's financial condition, results of operations or cash flows.

Plant and Property

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

NW Natural's provision for depreciation of utility property is computed under the straight-line, age-life method in accordance with independent engineering studies and as approved by regulatory authorities. The weighted average depreciation rate for utility plant in service was approximately 3.4 percent for the years ended Dec. 31, 2005 and 2004 and 3.5 percent for 2003, reflecting the approximate economic life of the property.

Effective Jan. 1, 2003, the Company adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." Among other things, SFAS No. 143 requires that future asset retirement costs (removal costs) that meet the requirements of SFAS No. 71 be classified as a regulatory liability. In accordance with long-standing industry practice, the Company accrues for future removal costs on many long-lived assets through a charge to depreciation expense allowed in rates. At the time removal costs are incurred, accumulated depreciation is charged with the costs of removal and the book cost of the asset. At Dec. 31, 2005 and 2004, the Company recognized accrued asset removal costs of $169.9 million and $153.2 million, respectively, through depreciation expense. The Company's estimate of accumulated removal costs is based on rates using our most recent depreciation study. The Company will continue to accrue future asset removal costs through depreciation expense, with a corresponding credit to regulatory liabilities—accrued asset removal costs. When the Company retires depreciable utility plant and equipment, it charges the associated original costs to accumulated depreciation and amortization, and any related removal costs incurred are charged to regulatory liabilities—accrued asset removal costs. No gain or loss is recognized upon normal retirement. In the rate setting process, the accrued asset removal costs are treated as a reduction to the net rate base.

Allowance for Funds Used During Construction

Certain additions to utility plant include an allowance for funds used during construction, which represents the cost of funds used during construction and is calculated using actual commercial paper interest rates. If commercial paper borrowings are less than the total costs of construction work in progress, then a composite rate of interest on all debt, shown as a reduction to interest charges, and a return on equity funds, shown as other income, is used to compute the allowance. While cash is not realized currently from allowance for funds used during construction, it is realized in future years through increased revenues from rate recovery resulting from higher rate base and higher depreciation expense. Our composite allowance for funds used during construction rates were 3.1 percent in 2005, 3.0 percent in 2004 and 4.5 percent in 2003.

Cash and Cash Equivalents

For purposes of reporting cash flows, cash and cash equivalents include cash on hand and highly liquid temporary investments with original maturity dates of three months or less.

Revenue Recognition and Accrued Unbilled Revenues

Utility revenues, derived primarily from the sale and transportation of natural gas, are recognized when the gas is delivered to and received by the customer. Revenues include accruals for gas delivered but not yet billed to customers based on estimates of gas deliveries from meter reading dates to month end (accrued unbilled revenues). Accrued unbilled revenues are dependent upon a number of factors that require management's judgment, including total gas receipts and deliveries, customer use and weather. Accrued unbilled revenues are reversed the following month when actual billings occur. The Company's accrued unbilled revenues at Dec. 31, 2005 and 2004 were $81.5 million and $64.4 million, respectively.

Non-utility revenues, derived primarily from gas storage services, are recognized upon delivery of the service to customers. Revenues from optimization of excess storage and transportation capacity are recognized over the life of the contract for guaranteed amounts under the contract, or are recognized as they are earned for amounts above the guaranteed value based on estimates provided by the independent energy marketing company (see Note 2).

Accounts Receivable and Allowance for Uncollectible Accounts

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

Inventories

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

Derivatives Policy

NW Natural's Derivatives Policy sets forth the guidelines for using selected financial derivative products to support prudent risk management strategies within designated parameters. The

Derivatives Policy allows for the use of derivatives to manage natural gas commodity prices related to natural gas purchases, foreign currency prices related to gas purchase commitments from Canada, oil or propane commodity prices related to gas sales and transportation services under rate schedules pegged to other commodities, and interest rates related to long-term debt maturing in less than five years or expected to be issued in future periods. NW Natural's objective for using derivatives is to decrease the volatility of earnings and cash flows associated with changes in commodity prices, foreign currency prices and interest rates. The use of derivatives is permitted only after the commodity price, exchange rate, and interest rate exposures have been identified, are determined to exceed acceptable tolerance levels and are considered to be unavoidable because they are necessary to support normal business activities (see Note 11). The Derivatives Policy is intended to prevent speculative risk. NW Natural does not enter into derivative instruments for trading purposes and believes that any increase in market risk created by holding derivatives should be offset by the exposures they modify.

In accounting for derivative activities, the Company applies SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities," and SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," (collectively referred to as SFAS No. 133). SFAS No. 133 requires that the Company recognize derivatives as either assets or liabilities on the balance sheet and measure those instruments at fair value. SFAS No. 133 also requires that changes in the fair value of a derivative be recognized currently in earnings unless specific hedge accounting criteria are met. SFAS No. 133 provides an exception for contracts intended for normal purchases and normal sales, other than a financial instrument or derivative instrument for which physical delivery is probable. Prior to March 31, 2005, the Company's forward gas supply contracts were excluded from the fair value measurement requirement of SFAS No. 133 because these contracts were eligible for the normal purchase and normal sale exception. In 2005, NW Natural entered into a series of exchange transactions with an unaffiliated energy marketing company which resulted in a change in the Company's accounting treatment for its forward gas supply contracts under SFAS No. 133. These contracts are now accounted for as derivative instruments and marked-to-market based on fair value pursuant to SFAS No. 133.

Due to the forward gas supply contracts being classified as derivatives for accounting purposes, the corresponding derivative financial contracts originally designated as cash flow hedges no longer qualify for hedge accounting under SFAS No. 133, even though these contracts continue to hedge the financial risk exposure of the forward gas supply contracts. However, due to regulatory deferral accounting under SFAS No. 71, the change in classification had no impact on the Company's financial condition, results of operations or cash flows.

Unrealized gains and losses from mark-to-market valuations of these contracts are not recognized in current income but are reported as derivative assets or liabilities and offset by a corresponding deferred account balance included under "regulatory liabilities" or "regulatory assets." Due to their regulatory deferral treatment, effective portions of changes in the fair value of these derivatives are not recorded in other comprehensive income but are recognized as a regulatory asset or liability.

Income Taxes

NW Natural accounts for income taxes in accordance with SFAS No. 109, "Accounting for Income Taxes." SFAS No. 109 requires recognition of deferred tax liabilities and assets for the expected future tax consequences of items that have been included in the financial statements or tax returns. Deferred income taxes represent the future net tax effects resulting from temporary differences between the financial statement and tax bases of assets and liabilities, using enacted tax rates in effect for the year in which the differences are expected to reverse (see Note 8).

SFAS No. 109 also requires recognition of the additional deferred income tax assets and liabilities for temporary differences where regulators prohibit deferred income tax treatment for ratemaking purposes. The Company has recorded a deferred tax liability equivalent to $65.8 million and $64.7 million at Dec. 31, 2005 and 2004, to recognize future taxes payable resulting from transactions that have previously been reflected in the financial statements for these temporary differences. Regulatory assets or liabilities corresponding to such additional deferred income tax assets or liabilities may be recorded to the extent the Company believes they will be recoverable from or payable to customers through the ratemaking process. Pursuant to SFAS No. 71, a corresponding regulatory asset has been recorded which represents the probable future revenue that will result from inclusion in rates charged to customers of taxes which will be paid in the future. The probable future revenue to be recorded takes into consideration the additional future taxes which will be generated by that revenue. Amounts applicable to income taxes due from customers primarily represent differences between the book and tax bases of net utility plant in service and actual removal costs incurred.

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

Other Income (Expense)

Other income (expense) consists of interest income, gain on sale of investments, investment income of Financial Corporation and other miscellaneous income from merchandise sales, rents, leases and other items.

Earnings Per Share

Basic earnings per share are computed based on the weighted average number of common shares outstanding each year. Diluted earnings per share reflect the potential effects of the conversion of convertible debentures and the exercise of stock options. Diluted earnings per share are calculated as follows:

Thousands, except per share amounts	2005	2004	2003
Net income	$58,149	$50,572	$45,983
Redeemable preferred stock dividend requirements	-	-	294
Earnings applicable to common stock - basic	58,149	50,572	45,689
Convertible debenture interest less taxes	-	200	257
Earnings applicable to common stock - diluted	$58,149	$50,772	$45,946
Average common shares outstanding - basic	27,564	27,016	25,741
Stock options	57	40	28
Convertible debentures	-	227	292
Average common shares outstanding - diluted	27,621	27,283	26,061
Earnings per share of common stock - basic	$ 2.11	$ 1.87	$ 1.77
Earnings per share of common stock - diluted	$ 2.11	$ 1.86	$ 1.76

For the years ended Dec. 31, 2005, 2004 and 2003, 6,000 shares, 201,800 shares and 77,500 shares, respectively, representing the number of stock options the exercise prices for which were greater than the average market prices for the common stock for such years, were excluded from the calculation of diluted earnings per share because the effect was antidilutive.

Stock-Based Compensation

The Company periodically provides stock-based compensation to employees in the form of stock options and similar awards. As permitted by SFAS No. 123, "Share Based Payment," the Company currently applies APB Opinion No. 25, "Accounting for Stock Issued to Employees," to account for its stock-based compensation. Accordingly, the Company does not recognize compensation expense for the fair value of its stock option grants. In December 2004, the FASB issued SFAS No. 123 (revised 2004), "Share-Based Payment," which revises SFAS No. 123, and supersedes APB Opinion No. 25. SFAS No.123R requires all share-based payments to be recognized as compensation expense in the financial statements. The Company will implement the new standard in the first quarter of 2006 by applying the modified prospective transition method. The impact on net income of this new standard had it been adopted in 2005 is reflected in the pro forma amounts in Note 4. The Company currently recognizes and will continue to recognize compensation expense for the fair value of stock awards granted under its Long-Term Incentive Plan and the Non-Employee Directors Stock Compensation Plan in the period when the shares are earned (see "New Accounting Standards—Recent Accounting Pronouncements—Share Based Payments," above, and Note 4).

2. CONSOLIDATED SUBSIDIARY OPERATIONS AND SEGMENT INFORMATION:

At Dec. 31, 2005, the Company had one active, direct wholly-owned subsidiary, Financial Corporation.

Our core business segment, local gas distribution, also referred to as the "utility," involves the distribution and sale of natural gas. Another segment, interstate gas storage, represents natural gas storage services provided to interstate customers, including asset optimization services under a contract with an independent energy marketing company. The remaining business segment, "other," primarily consists of non-regulated investments in alternative energy projects in California (see "Financial Corporation," below), a Boeing 737-300 aircraft leased to Continental Airlines and low-income housing in Portland, Oregon (see Note 9).

Interstate Gas Storage

Interstate gas storage services are provided to off-system interstate customers using Company-owned storage capacity that has been developed in advance of core utility customers' (residential, commercial and industrial firm) requirements. NW Natural retains 80 percent of the income before tax from gas storage services and credits the remaining 20 percent to a deferred regulatory account for sharing with core utility customers. For each of the years ended Dec. 31, 2005, 2004 and 2003, this business segment derived a majority of its revenues from fewer than five customers. The largest of these customers is served under a long-term contract.

Results for the interstate gas storage segment also include revenues, net of amounts shared with core utility customers, from a contract with an independent energy marketing company that optimizes the use of the Company's assets by engaging in trading activities using temporarily unused portions of its upstream pipeline transportation capacity and gas storage capacity. In Oregon, NW Natural retains 80 percent of the pre-tax income from the optimization of storage and pipeline transportation capacity when the costs of such capacity have not been included in core utility rates, and retains 33 percent of the pre-tax income from such capacity when the costs have been included in core utility rates. The remaining 20 percent and 67 percent, respectively, are credited to a deferred regulatory account for distribution to core utility customers. NW Natural has a similar sharing mechanism in Washington for revenue derived from interstate gas storage services and third party optimization services.

Financial Corporation

Financial Corporation has several financial investments, including investments as a limited partner in windpower electric generating projects and low-income housing projects. Financial Corporation's total assets were $3.3 million and $7.6 million at Dec. 31, 2005 and 2004, respectively. On Jan. 31, 2005, Financial Corporation sold limited partnership interests in three solar electric generating systems for approximately $3 million, which resulted in a $0.5 million write-down of these systems in the fourth quarter of 2004.

Segment Information Summary

The following table presents summary financial information about the reportable segments for 2005, 2004 and 2003. Inter-segment transactions are insignificant.

Thousands	Utility	Interstate Gas Storage	Other	Total
2005				
Net operating revenues	$ 315,248	$ 9,609	$ 136	$ 324,993
Depreciation and amortization	60,935	710	-	61,645
Income (loss) from operations	118,794	8,158	(5)	126,947
Income from financial investments	1,856	-	57	1,913
Net income	52,759	4,557	833	58,149
Total assets at Dec. 31, 2005	1,994,595	34,574	12,862	2,042,031
2004				
Net operating revenues	$ 284,904	$ 6,423	$ 168	$ 291,495
Depreciation and amortization	56,899	472	-	57,371
Income (loss) from operations	104,781	5,299	(54)	110,026
Income from financial investments	2,855	-	181	3,036
Net income	47,090	2,880	602	50,572
Total assets at Dec. 31, 2004	1,688,688	28,361	15,146	1,732,195
2003				
Net operating revenues	$ 264,206	$ 9,036	$ 174	$ 273,416
Depreciation and amortization	53,798	451	-	54,249
Income from operations	94,439	7,781	52	102,272
Income from financial investments	3,406	-	474	3,880
Net income	40,913	4,312	758	45,983
Total assets at Dec. 31, 2003	1,551,817	19,036	14,526	1,585,379

3. CAPITAL STOCK:

Common Stock

At Dec. 31, 2005, NW Natural had reserved 75,803 shares of common stock for issuance under the Employee Stock Purchase Plan, 867,072 shares under its Dividend Reinvestment and Direct Stock Purchase Plan, 1,538,300 shares under its Restated Stock Option Plan (see Note 4), and 3,000,000 shares under the Shareholder Rights Plan.

In April 2004, the Company issued and sold 1,290,000 shares of its common stock in an underwritten public offering and used the net proceeds of $38.5 million from the offering primarily to reduce short-term indebtedness and to fund, in part, NW Natural's utility construction program.

Expiration of Common Share Purchase Rights

In February 2006, the Company's Board of Directors decided to allow all of the common stock purchase rights ("Rights") issued under the Rights Agreement, dated as of February 27, 1996, as amended, between NW Natural and American Stock Transfer and Trust Company, to expire in accordance with their terms at the close of business on March 15, 2006.

Stock Repurchase Program

NW Natural's Board of Directors approved a stock repurchase program in 2000 to purchase up to 2 million shares, or up to $35 million in value, of NW Natural's common stock in the open market or through privately negotiated transactions. The repurchase program has been extended through May 2006. A total of 410,200 shares were repurchased under this program in 2005; however, no shares were repurchased in 2003 or 2004. Since the program's inception, the Company has repurchased 765,600 shares of common stock at a total cost of $23.1 million.

Restated Stock Option Plan

There are 2,400,000 shares authorized for option grants under the Restated Stock Option Plan. At Dec. 31, 2005, options on 1,229,800 shares were available for grant and options on 308,500 shares were outstanding.

Convertible Debentures

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

The following table shows the changes in the number of shares of NW Natural's capital stock and the premium on common stock for the years 2005, 2004 and 2003:

	Shares		
	Common stock	Redeemable preferred stock	Premium on common stock (thousands)
Balance, Dec. 31, 2002	25,586,313	82,500	$248,028
Sales to employees	14,175	-	425
Sales to stockholders	178,714	-	4,347
Exercise of stock options - net	127,357	-	2,545
Conversion of convertible debentures to common	31,443	-	526
Sinking fund purchases	-	(7,500)	-
Early redemption	-	(75,000)	-
Balance, Dec. 31, 2003	25,938,002	-	255,871
Sales to public	1,290,000	-	35,905
Sales to employees	27,541	-	605
Sales to stockholders	157,124	-	4,323
Exercise of stock options - net	73,649	-	2,285
Conversion of convertible debentures to common	64,904	-	1,086
Repurchase	(4,500)	-	(41)
Balance, Dec. 31, 2004	27,546,720	-	300,034
Sales to employees	30,896	-	741
Sales to stockholders	113,925	-	3,741
Exercise of stock options - net	97,068	-	2,241
Conversion of convertible debentures to common	200,887	-	3,360
Repurchase	(410,200)	-	(13,646)
Balance, Dec. 31, 2005	27,579,296	-	$296,471

4. STOCK-BASED COMPENSATION:

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

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

At year-end 2005, 433,000 shares of common stock were available for award under the LTIP, assuming that outstanding performance based grants are awarded at the target level. The LTIP stock awards are compensatory awards for which compensation expense is recognized based on the market value of performance shares earned, or a pro rata amortization over the vesting period for the outstanding restricted stock award.

Performance-based Stock Awards. Since the Plan's inception in 2001 through Dec. 31, 2005, performance-based stock awards have been granted annually based on three-year performance periods. At Dec. 31, 2005, all performance-based stock awards other than those covering the 2004-06 and 2005-07 periods had lapsed because the performance-based measures were not achieved. If the performance-based measures are achieved, at the end of the measurement period participants will receive shares of common stock and dividend equivalent cash payments equal to the number of shares of common stock received on the award payout multiplied by the aggregate cash dividends paid per share by the Company during the performance period.

No awards were paid for the three-year performance period that ended Dec. 31, 2005 because the performance measure was not achieved. For this performance period, a series of performance targets was established based on the Company's average annual return on equity (ROE) that was tied to the Company's authorized ROE.

At Dec. 31, 2005, the aggregate number of performance-based shares awarded and outstanding at the threshold, target and maximum levels were as follows:

Year Awarded	Performance Period	No. of Performance Shares Awarded		
		Threshold	Target	Maximum
2004	2004-06	6,750	27,000	54,000
2005	2005-07	8,750	35,000	70,000
	Total	15,500	62,000	124,000

For the 2004-06 and 2005-07 performance periods, awards will be based on total shareholder return relative to a peer group of gas distribution companies over the three-year performance period and on performance milestones relative to the Company's core and non-core strategies.

During the performance period, the Company will recognize compensation expense and liability for the LTIP awards based on performance levels achieved, and expected to be achieved, and the estimated market value of the common stock as of the distribution date. For the 12 months ended Dec. 31, 2005, $0.7 million and $0.5 million were accrued as compensation expense under the LTIP for the 2004-06 and 2005-07 performance periods, respectively.

Restricted Stock Awards. Restricted stock awards also have been granted under the LTIP. A restricted stock award consisting of 4,500 shares granted in 2001 lapsed in 2004, and a restricted stock award was granted in 2004 consisting of 5,000 shares that will vest ratably over the period 2005-09. In accordance with APB Opinion No. 25, compensation expense is recognized ratably over the vesting period.

Restated Stock Option Plan. The Restated SOP authorizes an aggregate of 2,400,000 shares of common stock for issuance as incentive or non-statutory stock options. These options may be granted only to officers and key employees designated by a committee of our Board of Directors. All options are granted at an option price not less than the market value at the date of grant and may be exercised for a period not exceeding 10 years from the date of grant. Option holders may exchange shares they have owned for at least six months, at the current market price, to purchase shares at the option price. Since inception in 1985, options on 1,312,721 shares of common stock have been granted at prices ranging from $11.75 to $38.30 per share, and options on 145,521 shares have expired.

Employee Stock Purchase Plan. The ESPP allows employees to purchase common stock at 85 percent of the closing price on the trading day immediately preceding the subscription date, which is set annually. Each eligible employee may purchase up to $24,000 worth of stock through payroll deductions over a six- to 12-month period.

In accordance with APB Opinion No. 25, no compensation expense was recognized for options granted under the Restated SOP or shares issued under the ESPP during 2005 or earlier years (see Note 1, "New Accounting Standards—Recent Accounting Pronouncements"). If compensation expense for awards under these two plans had been determined based on fair value at the grant dates using the method prescribed by SFAS No. 123R, "Accounting for Stock-Based Compensation," net income and earnings per share would have been reduced to the pro forma amounts shown below:

Thousands, except per share amounts	2005	2004	2003
Net income as reported	$58,149	$50,572	$45,983
Add: Stock based compensation expense included in reported net income - net of tax	613	96	-
Deduct: Pro forma stock-based compensation expense determined under the fair value based method - net of tax	(940)	(519)	(279)
Pro forma net income	57,822	50,149	45,704
Redeemable preferred and preference stock	-	-	(294)
Pro forma earnings applicable to common stock - basic	57,822	50,149	45,410
Debenture interest less taxes	-	200	257
Pro forma earnings applicable to common stock - diluted	$57,822	$50,349	$45,667
Basic earnings per share			
As reported	$ 2.11	$ 1.87	$ 1.77
Pro forma	$ 2.10	$ 1.86	$ 1.76
Diluted earnings per share			
As reported	$ 2.11	$ 1.86	$ 1.76
Pro forma	$ 2.09	$ 1.85	$ 1.75

The fair value of each stock option is estimated on the grant date (there were no stock option grants in 2003) using the Black-Scholes option pricing model with the following weighted average assumptions:

	2005	2004
Expected life in years	7.0	7.0
Risk-free interest rate	4.2%	3.6%
Expected volatility	24.6%	25.2%
Dividend yield	3.6%	4.1%
Present value of options granted	$ 27.87	$ 24.55

Information regarding the Restated SOP's activity for the three years ended Dec. 31, 2005 is summarized as follows:

	Option Shares	Price per Share: Range	Price per Share: Weighted-Average Exercise Price
Balance outstanding, Dec. 31, 2002	463,814	$20.25 - 27.875	$24.10
Exercised	(140,470)	20.25 - 27.875	21.14
Expired	(1,300)	20.25	20.25
Balance outstanding, Dec. 31, 2003	322,044	20.25 - 27.875	25.35
Granted	202,800	31.34 - 32.020	31.40
Exercised	(92,074)	20.25 - 27.875	24.39
Expired	(1,300)	26.30 - 31.340	30.18
Balance outstanding, Dec. 31, 2004	431,470	20.25 - 32.020	28.38
Granted	9,000	34.95 - 38.30	37.18
Exercised	(121,170)	20.25 - 31.34	26.59
Expired	(10,800)	27.60 - 31.34	30.79
Balance outstanding, Dec. 31, 2005	308,500	$20.25 - 38.30	$29.26
Shares available for grant Dec. 31, 2003	1,429,500		
Shares available for grant Dec. 31, 2004	1,228,000		
Shares available for grant Dec. 31, 2005	1,229,800		

The weighted average remaining life of outstanding stock options at Dec. 31, 2005 was 6.8 years.

The characteristics of exercisable stock options at Dec. 31, 2005 were as follows:

Range of Exercise Prices	Exercisable Stock Options	Weighted-Average Exercise Price
$20.25 - $32.02	189,500	$27.63

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

Prior to the latter amendment to the NEDSCP, if non-employee directors elected to receive their awards in stock, approximately $100,000 worth of common stock was awarded upon joining the Board. These stock awards were subject to vesting and to restrictions on sale and transferability. The shares vested in monthly installments over the five calendar years following the award. On January 1 of each year following the initial award, non-employee directors who elected to receive their awards in Company stock were awarded an additional $20,000 worth of restricted Company stock, which vested in monthly installments in the fifth year following the award (after the previous award had fully vested). The Company holds the certificates for the restricted shares until the non-employee director ceases to be a director. Participants receive all dividends and have full voting rights on both vested and unvested shares. All awards vest immediately upon the death of a director or upon a change in control of the Company. Any unvested shares are considered to be unearned compensation, and thus are forfeited if the recipient ceases to be a director. The shares were purchased in the open market by the Company at the time of the award.

The following table presents the changes in unearned stock compensation for the years 2005 and 2004, which are reported as a reduction to total common equity in the consolidated balance sheets:

Thousands	2005	2004
Unearned stock compensation:		
Balance at beginning of year	$ 862	$ 729
Purchases of restricted stock	-	431
Restricted stock amortizations	(212)	(298)
Balance at end of year	$ 650	$ 862

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

5. LONG-TERM DEBT:

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

The maturities on the long-term debt outstanding, for each of the 12-month periods through Dec. 31, 2010 amount to: $8 million in 2006; $29.5 million in 2007; $5 million in 2008, none in 2009; and $35 million in 2010. Holders of certain long-term debt have put options that, if exercised, would accelerate the maturities by $20 million in each of 2007, 2008 and 2009.

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

In July 2005, the Company redeemed three series of its maturing MTNs aggregating $15 million in principal amount. The series redeemed were the 6.34% Series B, the 6.38% Series B and the 6.45% Series B, each with a principal balance outstanding of $5 million due in July 2005. The MTNs were redeemed with proceeds from the sales of $50 million in principal amount of MTNs in June 2005.

6. NOTES PAYABLE AND LINES OF CREDIT:

The Company's primary source of short-term funds is from the sale of commercial paper notes payable. In addition to issuing commercial paper to meet seasonal working capital requirements, including the financing of gas purchases and accounts receivable, short-term debt is also used temporarily to fund capital requirements. Commercial paper is periodically refinanced through the sale of long-term debt or equity securities. NW Natural's commercial paper program is supported by committed bank lines of credit (see below). At December 31, 2005 and 2004, the amounts and average interest rates of commercial paper debt outstanding were $126.7 million and 4.3 percent and $102.5 million and 2.3 percent, respectively. NW Natural has not issued commercial paper in an aggregate amount outstanding in excess of its committed lines of credit.

In September 2005, NW Natural entered into an agreement for unsecured lines of credit totaling $200 million with five commercial banks, replacing the existing $150 million credit facilities. The new bank lines of credit (bank lines) are available and committed for a term of five years, beginning Oct. 1, 2005 and expiring on Sept. 30, 2010. NW Natural's bank lines are used primarily as back-up support for the notes payable under the Company's commercial paper borrowing program. Commercial paper borrowing provides the liquidity to meet the working capital and external financing requirements of NW Natural.

Under the terms of these bank lines, NW Natural pays upfront fees and annual commitment fees but is not required to maintain compensating bank balances. The interest rates on outstanding loans, if any, under these bank lines are based on then-current market interest rates. All principal and unpaid interest under the bank lines is due and payable on Sept. 30, 2010.

The bank lines require that NW Natural maintain credit ratings with Standard & Poor's and Moody's Investors Service and to notify the banks of any change in its senior unsecured debt ratings by such rating agencies. A change in NW Natural's credit rating is not an event of default, nor is the maintenance of a specific minimum level of credit rating a condition of drawing upon the bank lines. However, interest rates on any loans outstanding under these bank lines are tied to credit ratings, which would increase or decrease the cost of any loans under the bank lines when ratings are changed.

The bank lines also require the Company to maintain an indebtedness to total capitalization ratio of 65 percent or less. Failure to comply with this covenant would entitle the banks to terminate their lending commitments and to accelerate the maturity of all amounts outstanding. NW Natural was in compliance with this covenant at Dec. 31, 2005, with an indebtedness to total capitalization ratio of 53.5 percent.

7. PENSION AND OTHER POSTRETIREMENT BENEFITS:

NW Natural maintains two qualified non-contributory defined benefit pension plans covering all regular employees with more than one year of service, several non-qualified supplemental pension plans for eligible executive officers and certain key employees and other postretirement benefit plans for employees. Only the two qualified defined benefit pension plans have plan assets, which are held in a qualified trust to fund retirement benefits.

The following table provides a reconciliation of the changes in benefit obligations and fair value of assets, as applicable, for the pension plans and other postretirement benefit plans over the three-year period ended Dec. 31, 2005, and a statement of the funded status and amounts recognized in the consolidated balance sheets, using measurement dates of Dec. 31, 2005, 2004 and 2003:

	Post-Retirement Benefits					
	Pension Benefits			Other Postretirement Benefits		
Thousands	2005	2004	2003	2005	2004	2003
Change in benefit obligation:						
Benefit obligation at Jan. 1	$222,948	$205,352	$185,124	$ 22,729	$ 23,379	$ 18,457
Service cost	6,322	5,428	4,748	767	457	456
Interest cost	13,203	12,690	12,402	1,248	1,232	1,336
Special termination benefits	-	237	-	-	-	-
Expected benefits paid	(12,866)	(10,682)	(10,363)	(1,173)	(1,040)	(1,027)
Change in assumptions	31,642	-	-	2,215	-	-
Plan amendments	1,408	-	-	2,384	-	(111)
Net actuarial (gain) loss	5,197	9,923	13,441	(7,773)	(1,299)	4,268
Benefit obligation at Dec. 31	267,854	222,948	205,352	20,397	22,729	23,379
Change in plan assets:						
Fair value of plan assets at Jan. 1	186,787	168,324	143,164	-	-	-
Actual return on plan assets	12,558	19,835	34,520	-	-	-
Employer contributions	32,076	9,310	1,003	1,173	1,040	1,027
Benefits paid	(12,866)	(10,682)	(10,363)	(1,173)	(1,040)	(1,027)
Fair value of plan assets at Dec. 31	218,555	186,787	168,324	-	-	-
Funded status:						
Funded status at Dec. 31	(49,299)	(36,162)	(37,028)	(20,397)	(22,729)	(23,379)
Unrecognized transition obligation	-	-	-	2,880	3,292	3,703
Unrecognized prior service cost	6,492	5,146	6,240	2,243	-	-
Unrecognized net actuarial loss	69,766	33,897	32,156	988	6,717	8,304
Net amount recognized	$ 26,959	$ 2,881	$ 1,368	$(14,286)	$(12,720)	$(11,372)
Amounts recognized in the consolidated balance sheets at Dec. 31:						
Prepaid benefit cost	$ 36,830	$ 12,745	$ 11,113	$ -	$ -	$ -
Accrued benefit liability	(12,910)	(12,919)	(11,319)	(14,286)	(12,720)	(11,372)
Intangible asset	-	-	-	-	-	-
Other comprehensive loss	3,039	3,055	1,574	-	-	-
Net amount recognized	$ 26,959	$ 2,881	$ 1,368	$(14,286)	$(12,720)	$(11,372)

The Company's qualified defined benefit pension plans had a benefit obligation in excess of plan assets at Dec. 31, 2005. The plans' aggregate benefit obligation was $254 million, $209 million and $192 million at Dec. 31, 2005, 2004 and 2003, respectively, and the fair value of plan assets was $218.6 million, $186.8 million and $168.3 million, respectively. The benefit obligation at Dec. 31, 2005 increased $26.6 million from Dec. 31, 2004 due to the use of updated mortality rates and increased $8.1 million due to the 0.25 percent decrease in the discount rate. The fair value of plan assets increased from Dec. 31, 2004 to Dec. 31, 2005 due to $13.5 million in investment gains and employer contributions of $31 million, partially offset by $11.8 million in withdrawals to pay benefits and $0.9 million to pay eligible expenses of the plans. The combination of investment returns and future cash contributions is expected to provide sufficient funds to cover all benefit obligations of the plans.

The discount rate at Dec. 31, 2005 was determined by developing a spot rate yield curve using the pension plans' estimated future benefit payments applied to a portfolio of Moody's AA or better rated bonds.

The expected long-term rate of return was developed by averaging the expected earnings for the target asset portfolio. In developing the expected long-term rate of return assumption, consideration was given to the historical performance of the asset classes in which the plans' assets are invested and the target asset allocation for plan assets. The annualized returns for the past one, five and 10 years ended Dec. 31, 2005 were 7.4 percent, 5.9 percent and 10.1 percent, respectively.

The Company's Statement of Investment Policy and Performance Objectives for the qualified pension plan assets (plan assets) held in the Retirement Trust Fund was approved by the retirement committee which is composed of management employees. The policy sets forth the guidelines and objectives governing the investment of plan assets. Plan assets are invested for total return with appropriate consideration for liquidity and portfolio risk. All investments are expected to satisfy the requirements of the rule of prudent investments as set forth under the Employee Retirement Income Security Act of 1974. The approved asset classes are cash and short-term investments, fixed income, common stock and convertible securities, absolute and real return strategies, real estate and investments in Company securities, and may be invested in separately managed accounts or in commingled or mutual funds. Re-balancing will take place at least annually, or when significant cash flows occur, in order to maintain the allocation of assets within the stated target allocation ranges. The Retirement Trust Fund is not currently invested in any NW Natural securities.

The Company's pension plan asset allocation at Dec. 31, 2005 and 2004, and the target allocation and expected long-term rate of return by asset category for 2006, are as follows:

Asset Category	Percentage of Plan Assets Dec. 31, 2005	2004	Target Allocation 2006	Expected Long-term Rate of Return 2006
US large cap equity	19.8%	36.3%	20%	8.50%
US small/mid cap equity	14.2%	9.2%	15%	9.50%
Non-US equity	19.7%	19.2%	20%	8.75%
Fixed income	19.3%	19.8%	15%	5.50%
Real estate	6.2%	3.6%	8%	7.75%
Absolute return strategies	14.2%	7.3%	15%	9.00%
Real return	6.6%	4.6%	7%	7.75%
Weighted average				8.25%

The Company's non-qualified supplemental pension plans' benefit obligations were $13.5 million, $13.6 million and $13.0 million at Dec. 31, 2005, 2004 and 2003, respectively. Although the plans are unfunded plans with no plan assets due to their nature as non-qualified plans, the Company indirectly funds its obligations with trust-owned life insurance.

The Company's plans for providing postretirement benefits other than pensions also are unfunded plans. The aggregate benefit obligation for those plans was $20.4 million, $22.7 million and $23.4 million at Dec. 31, 2005, 2004 and 2003, respectively.

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

The following tables provide the components of net periodic benefit cost for the qualified and non-qualified pension and other postretirement benefit plans for the years ended Dec. 31, 2005, 2004 and 2003 and the assumptions used in measuring these costs and benefit obligations:

	Pension Benefits			Other Postretirement Benefits		
Thousands	2005	2004	2003	2005	2004	2003
Service cost	$ 6,322	$ 5,428	$ 4,748	$ 767	$ 457	$ 456
Interest cost	13,203	12,689	12,402	1,248	1,232	1,336
Expected return on plan assets	(14,449)	(13,284)	(12,232)	-	-	-
Amortization of transition obligation	-	-	-	411	411	411
Amortization of prior service cost	1,077	1,094	1,132	142	-	-
Recognized actuarial loss	2,082	1,631	1,058	173	288	401
Net periodic cost	$ 8,235	$ 7,558	$ 7,108	$ 2,741	$ 2,388	$ 2,604
Assumptions:						
Discount rate for net periodic benefit cost (NPBC)	6.00%	6.25%	6.75%	6.00%	6.25%	6.75%
Rate of increase in compensation for NPBC	4.00-5.00%	4.00-5.00%	4.25-5.00%	n/a	n/a	n/a
Expected long-term rate of return for NPBC	8.25%	8.25%	8.00%	n/a	n/a	n/a
Discount rate for determination of funded status	5.75%	6.00%	6.25%	5.75%	6.00%	6.25%
Rate of increase in compensation for funded status	4.00-5.00%	4.00-5.00%	4.00-5.00%	n/a	n/a	n/a
Expected long-term rate of return for funded status	8.25%	8.25%	8.25%	n/a	n/a	n/a

The assumed annual increase in trend rates used in measuring postretirement benefits as of Dec. 31, 2005 were 10 percent for medical and 13 percent for prescription drugs. Medical costs were assumed to decrease gradually each year to a rate of 4.5 percent for 2013, while prescription drug costs were assumed to decrease gradually each year to a rate of 4.5 percent for 2013.

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

Thousands	1% Increase	1% Decrease
Effect on the total service and interest cost components of net periodic postretirement health care benefit cost	$ 61	$ (60)
Effect on the health care component of the postretirement benefit obligation	$650	$(665)

The following table provides information regarding employer contributions and benefit payments for the two qualified pension plans, the non-qualified pension plans and the other postretirement benefit plans for the years ended Dec. 31, 2005 and 2004, and estimated future payments:

Thousands		
Employer Contributions by Plan Year	Pension Benefits	Other Benefits
2004	$ 26,390	$ 1,040
2005	12,497	1,173
2006 (estimated)	1,598	1,433
Benefit Payments		
2003	$ 10,363	$ 1,027
2004	10,682	1,040
2005	12,866	1,173
Estimated Future Payments		
2006	$ 12,773	$ 1,433
2007	13,069	1,497
2008	14,017	1,571
2009	14,671	1,598
2010	15,731	1,689
2011-2015	89,931	9,034

NW Natural's Retirement K Savings Plan (RKSP) is a qualified defined contribution plan under Internal Revenue Code Section 401(k). NW Natural also has non-qualified deferred compensation plans for eligible officers and senior managers. These plans are designed to enhance the retirement program of employees and to assist them in strengthening their financial security by providing an incentive to save and invest regularly. NW Natural's matching contributions to these plans totaled $1.7 million in both 2005 and 2004, and $1.6 million in 2003. The RKSP includes an Employee Stock Ownership Plan.

In addition, in 2005 the Company began making contributions on behalf of each union employee to the Western States Office and Professional Employees Pension Fund.

8. INCOME TAXES:

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

Thousands	2005	2004	2003
Computed income taxes based on statutory federal income tax rate of 35%	$31,804	$ 26,986	$24,263
Increase (reduction) in taxes resulting from:			
Difference between book and tax depreciation	222	222	222
Current state income tax, net of federal tax benefit	2,913	2,554	2,310
Federal income tax credits	(210)	(210)	(357)
Amortization of investment tax credits	(956)	(920)	(879)
Gains on Company and trust-owned life insurance	(650)	(955)	(1,192)
Removal costs	(813)	(813)	(925)
Reversal of amounts provided in prior years	336	(392)	(226)
Other - net	74	59	124
Total provision for income taxes	$32,720	$ 26,531	$23,340
Total income taxes paid	$28,479	$ 2,500	$11,814

The provision for income taxes consists of the following:

Thousands, except percentages	2005	2004	2003
Income taxes currently payable (receivable):			
Federal	$21,429	$ (9,607)	$10,011
State	1,605	(1,111)	1,175
Total	23,034	(10,718)	11,186
Deferred taxes - net:			
Federal	7,502	33,602	10,747
State	3,140	4,567	2,286
Total	10,642	38,169	13,033
Investment and energy tax credits restored:			
From utility operations	(784)	(800)	(801)
From subsidiary operations	(172)	(120)	(78)
Total	(956)	(920)	(879)
Total provision for income taxes	$32,720	$ 26,531	$23,340
Percentage of pretax income	36.0%	34.4%	33.7%

Deferred tax assets and liabilities are comprised of the following:

Thousands	2005	2004
Deferred tax liabilities:		
Plant and property	$149,901	$146,657
Regulatory income tax assets	65,843	64,734
Regulatory liabilities	3,045	5,730
Other deferred liabilities	4,670	5,534
Total	223,459	222,655
Deferred tax assets:		
Minimum pension liability	1,128	1,068
Other deferred assets	-	7,330
Alternative minimum tax credit carryforward	-	1,631
Loss and credit carryforwards	-	1,546
Total	1,128	11,575
Net accumulated deferred income tax liability	$222,331	$211,080

The amount of income taxes paid in 2004 decreased significantly as compared to the total provision for income taxes, primarily due to the effects of the accelerated bonus depreciation provisions of the Job Creation and Worker Assistance Act of 2002 (the Assistance Act) and of the Jobs and Growth Tax Relief Reconciliation Act of 2003 (the Reconciliation Act). The Assistance Act provided for an additional depreciation deduction equal to 30 percent of an asset's adjusted basis. The Reconciliation Act increased this first-year additional depreciation deduction to 50 percent of an asset's adjusted basis. The additional first-year depreciation deduction is an acceleration of depreciation deductions that otherwise would have been taken in the later years of an asset's recovery period. The accelerated depreciation provisions in 2004 were the primary factors resulting in net operating losses (NOL) for tax purposes.

In 2005, the Company filed its 2004 federal and Oregon income tax returns, which reflected the federal NOL of $35.8 million and the Oregon NOL of $32.9 million. At Dec. 31, 2004, the Company estimated that the federal NOL would be $15.4 million and that the Oregon NOL would be $18.6 million. During 2005, an additional $20 million pension contribution was made to the Company's two qualified defined benefit pension plans for the 2004 Plan year (see Note 7). This additional pension contribution resulted in an increased tax deduction for both federal and Oregon purposes.

The increased federal NOL was carried back to 2002 and an application for refund was filed. A federal refund of $8.3 million was received in October 2005. In conjunction with recording the refund, the Company recorded an additional alternative minimum tax credit carryforward of $3.9 million and other federal tax credit carryforwards of $0.3 million. At Dec. 31, 2004, the Company recorded an estimated $1.6 million alternative minimum tax credit carryforward and other estimated federal tax credit carryforwards of $0.2 million. The Company applied all of its federal tax credit carryforwards totaling $6.0 million against its 2005 estimated federal current income tax liability. The Company partially offset its estimated 2005 Oregon taxable income by the NOL carryforward. The current income tax benefits recognized by the Oregon NOL and tax credit carryforwards reduced the estimated 2005 Oregon current income tax liability by approximately $2.7 million.

An Internal Revenue Service (IRS) examination of the Company's 2002 through 2004 consolidated federal income tax returns commenced during the third quarter of 2005. The IRS completed its examination of the 2003 federal tax return in January 2006, and completion of the examination of the 2002 and 2004 federal income tax returns is expected during 2006.

9. PROPERTY AND INVESTMENTS:

The following table sets forth the major classifications of the Company's utility plant and accumulated depreciation at Dec. 31:

	2005		2004	
Thousands, except percentages	Amount	Weighted Average Depreciation Rate	Amount	Weighted Average Depreciation Rate
Transmission and distribution systems	$1,575,545	3.2%	$1,509,475	3.2%
Utility storage	109,908	2.6%	109,613	2.6%
General	90,780	3.1%	91,229	3.4%
Intangible and other	66,354	8.4%	61,573	8.5%
Gas stored long-term	13,078	0.0%	13,434	0.0%
Utility plant in service	1,855,665	3.4%	1,785,324	3.4%
Assets held for future use	1,833		1,833	
Construction work in progress	17,946		7,815	
Total utility plant	1,875,444		1,794,972	
Accumulated depreciation	(536,867)		(505,286)	
Utility plant-net	$1,338,577		$1,289,686	

Accumulated depreciation does not include $169.9 million and $153.3 million at Dec. 31, 2005 and 2004, respectively, which represent accrued asset removal costs reflected on the balance sheets as regulatory liabilities (see Note 1).

The following table summarizes the Company's investments in non-utility plant at Dec. 31:

	2005		2004	
Thousands, except percentages	Amount	Weighted Average Depreciation Rate	Amount	Weighted Average Depreciation Rate
Non-utility storage	$34,486		$24,900	
Dock, land, oil station and other	4,953		4,728	
Non-utility plant in service	39,439	2.6%	29,628	2.3%
Construction work in progress	1,397		4,335	
Total non-utility plant	40,836		33,963	
Less accumulated depreciation	(5,990)		(5,244)	
Non-utility plant - net	$34,846		$28,719	

The following table summarizes the Company's other long-term investments, including financial investments in life insurance policies accounted for at fair value based on cash surrender values, equity investments in certain partnerships and joint ventures accounted for under the equity or cost methods, and a leveraged lease investment in an aircraft, at Dec. 31:

Thousands	2005	2004
Life insurance cash surrender value	$46,555	$45,011
Aircraft leveraged lease	6,884	6,621
Real estate partnership	1,502	1,500
Note receivable	1,237	1,240
Gas pipeline and other	1,434	1,619
Electric generation	839	4,627
Total other investments	$58,451	$60,618

Aircraft Leveraged Lease. In 1987, the Company invested in a Boeing 737-300 aircraft, which is leased to Continental Airlines for 20 years under a leveraged lease agreement.

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

Electric Generation. Financial Corporation held ownership interests ranging from 25 to 41 percent in wind power electric generation projects located near Livermore and Palm Springs, California at Dec. 31, 2005. The wind-generated power is sold to Pacific Gas and Electric Company and Southern California Edison Company under long-term contracts. In January 2005, Financial Corporation sold its limited partnership interests in three electric generating systems (see Note 2).

FASB Interpretation No. 46, "Consolidation of Variable Interest Entities," provides guidance for determining whether consolidation is required for entities over which control is achieved through means other than voting rights, know as "variable interest entities." The Company does not have any significant interests in variable interest entities for which it is a primary beneficiary.

10. FAIR VALUE OF FINANCIAL INSTRUMENTS:

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

	Dec. 31, 2005		Dec. 31, 2004	
Thousands	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-term debt including amount due within one year	$529,500	$579,382	$499,027	$567,926

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

11. USE OF FINANCIAL DERIVATIVES:

NW Natural enters into forward contracts and other related financial transactions for the purchase of natural gas that qualify as derivative instruments under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 138 and SFAS No. 149 (collectively referred to as SFAS No. 133). NW Natural utilizes derivative financial instruments to manage commodity prices related to natural gas supply requirements.

In the normal course of business, NW Natural enters into forward natural gas commodity purchase (gas supply) contracts to meet the requirements of core utility customers. In 2005, NW Natural entered into a series of exchange transactions with an unaffiliated energy marketing company, which resulted in a change in the Company's accounting treatment for its forward gas supply contracts under SFAS No. 133. SFAS No. 133 requires that derivative instruments be recorded on the balance sheet at fair value. Prior to March 31, 2005, the Company's forward gas supply contracts were excluded from the fair value measurement requirement of SFAS No. 133 because these contracts were eligible for the normal purchase and normal sale exception. These physical supply contracts are now accounted for as derivative instruments and marked-to-market based on fair value pursuant to SFAS No. 133. These contracts include 25 index-based supply contracts, four fixed-price supply contracts and three physical option contracts. The mark-to-market adjustment for the forward gas supply contracts at Dec. 31, 2005 is an unrealized loss of $4.1 million, consisting of an unrealized loss of $5.5 million on index-based contracts, a $0.8 million unrealized gain on fixed-price contracts and a $0.6 million gain on physical option supply contracts. The net unrealized loss is recorded as a liability with an offsetting entry to a regulatory asset based on regulatory deferral accounting under SFAS No. 71, (see Note 1, "Industry Regulation").

Due to the forward gas supply contracts being classified as derivatives for accounting purposes, the corresponding derivative financial contracts originally designated as cash flow hedges no longer qualify for hedge accounting under SFAS No. 133, even though these contracts continue to hedge the financial risk exposure of the forward gas supply contracts. However, due to regulatory deferral accounting under SFAS No. 71, the accounting change had no impact on the Company's financial condition, results of operations or cash flows. The mark-to-market adjustment at Dec. 31, 2005 for the fixed-price financial swap contracts was an unrealized gain of $173.8 million.

Fixed-price financial call options are purchased to hedge the Company's forecasted purchases of winter swing supplies or spot gas. The mark-to-market adjustment at Dec. 31, 2005 was an unrealized gain of $1.9 million. These unrealized gains and losses were subject to regulatory deferral and, as such, were recorded as a non-trading derivative asset or liability which is offset by recording a corresponding amount to a deferred asset or liability account.

Certain natural gas purchases from Canadian suppliers are payable in Canadian dollars, including both commodity and demand charges, thereby exposing the Company to adverse changes in foreign currency rates. Foreign currency forward contracts are used to hedge the fluctuation in foreign currency exchange rates for NW Natural's commodity and commodity-related demand charges paid in Canadian dollars. Foreign currency contracts for commodity costs are purchased on a month-to-month basis because the Canadian cost is priced at the average noon-day exchange rate for each month. Foreign currency contracts for demand costs have terms ranging up to 12 months. The gains and losses on the shorter-term currency contracts for commodity costs are recognized immediately in cost of gas. The gains and losses on the currency contracts for demand charges are not recognized in current income but are subject to a regulatory deferral tariff and, as such, are recorded as a derivative asset or liability. These forward contracts qualify for cash flow hedge accounting treatment under SFAS No. 133. The mark-to-market adjustment at Dec. 31, 2005 was an unrealized gain of $0.2 million. These unrealized gains and losses were subject to regulatory deferral and, as such, were recorded as a derivative asset or liability which is offset by recording a corresponding amount to a regulatory asset or regulatory liability account. Certain contracts were in an over-hedged position at year-end due to a change in forecasted business requirements. The specific forward contracts involved were no longer designated as cash flow hedges, and the over-hedged position was immediately sold, resulting in a nominal gain which was deferred to a regulatory account.

NW Natural did not use any derivative instruments to hedge oil or propane prices or interest rates during 2005, 2004 or 2003.

At Dec. 31, 2005 and 2004, unrealized gains or losses from mark-to-market valuations of the Company's derivative instruments were not recognized in current income, but were reported as regulatory liabilities or regulatory assets because regulatory mechanisms provide for the realized gains or losses at settlement to be included in utility gas costs subject to regulatory deferral treatment. The estimated fair values (unrealized gains and losses) of derivative instruments outstanding were as follows:

	Fair Value Gains (Losses) Dec. 31,	
Thousands	2005	2004
Natural gas commodity-based derivative instruments:		
Fixed-price financial swaps	$173,790	$12,641
Fixed-price financial call options	1,871	(2,195)
Indexed-price physical supply	(5,454)	-
Fixed-price physical supply	820	-
Physical supply contracts with embedded options	567	24
Foreign currency forward purchases	183	442
Total	$171,777	$10,912

In 2005, 2004 and 2003, NW Natural realized net gains of $88.9 million, $42.4 million and $32.4 million, respectively, from the settlement of natural gas commodity swap and call option contracts, which were recorded as decreases to the cost of gas. The currency exchange rate in all foreign currency forward purchase contracts is included in our cost of gas at settlement; therefore, no gain or loss was recorded from the settlement of those contracts. Any change in value of cash flow hedge contracts that is not included in regulatory recovery is included in other comprehensive income.

The fair value of derivative instruments at Dec. 31, 2005 and 2004 (see table above) was determined using a discounted cash flow model for financial swaps and physical derivatives. A Black-Scholes model was used to value financial options.

As of Dec. 31, 2005, five of the natural gas commodity price swap contracts mature in 2007 and one contract matures in 2008. None of the natural gas commodity call option contracts extends beyond March 31, 2006.

12. COMMITMENTS AND CONTINGENCIES:

Lease Commitments

The Company leases land, buildings and equipment under agreements that expire in various years through 2045. Rental expense under operating leases was $4.1 million, $4.5 million and $4.9 million for the years ended Dec. 31, 2005, 2004 and 2003, respectively. The table below reflects the future minimum lease payments due under non-cancelable leases at Dec. 31, 2005. Such payments total $61.0 million for operating leases. The net present value of payments on capital leases less imputed interest was $0.3 million. These commitments principally relate to the lease of our office headquarters, underground gas storage facilities, vehicles and computer equipment.

Millions	2006	2007	2008	2009	2010	Later years
Operating leases	$4.4	$4.2	$4.1	$4.1	$4.1	$40.1
Capital leases	0.2	0.1	-	-	-	-
Minimum lease payments	$4.6	$4.3	$4.1	$4.1	$4.1	$40.1

Pipeline Capacity Purchase and Release Commitments

NW Natural has signed agreements providing for the reservation of firm pipeline capacity under which it must 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, NW Natural has entered into long-term sale agreements to release firm pipeline capacity. The aggregate amounts of these agreements were as follows at Dec. 31, 2005:

Thousands	Pipeline Capacity Purchase Agreements	Pipeline Capacity Release Agreements
2006	$ 69,482	$ 3,725
2007	64,831	3,725
2008	63,147	3,725
2009	56,970	3,725
2010	57,167	3,104
2011 through 2025	233,549	-
Total	545,146	18,004
Less: Amount representing interest	101,720	1,762
Total at present value	$443,426	$16,242

NW Natural's total payments of fixed charges under capacity purchase agreements in 2005, 2004 and 2003 were $83.1 million, $89.3 million and $86.7 million, respectively. Included in the amounts for 2005, 2004 and 2003 were reductions for capacity release sales of $3.7 million in each year. 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

NW Natural owns, or has previously owned, properties that may require environmental remediation or action. NW Natural accrues all material loss contingencies relating to these properties that it believes to be probable of assertion and reasonably estimable. The Company continues to study the extent of its potential environmental liabilities, but due to the numerous uncertainties surrounding the course of environmental remediation and the preliminary nature of several environmental site investigations, the range of potential loss beyond the amounts currently accrued, and the probabilities thereof, cannot be reasonably estimated. NW Natural regularly reviews its remediation liability for each site where it may be exposed to remediation responsibilities. The costs of environmental remediation are difficult to estimate. A number of steps are involved in each environmental remediation effort, including site investigations, remediation, operations and maintenance, monitoring and site closure. Each of these steps may, over time, involve a number of alternative actions, each of which can change the course of the effort. In certain cases, in addition to NW Natural, there are a number of other potentially responsible parties, each of which, in proceedings and negotiations with other potentially responsible parties and regulators, may influence the course of the remediation effort. The allocation of liabilities among the potentially responsible parties is often subject to dispute and highly uncertain. The events giving rise to environmental liabilities often occurred many decades ago, which complicates the determination of allocating liabilities among potentially responsible parties. Site investigations and remediation efforts often develop slowly over many years. To the extent reasonably estimable, NW Natural estimates the costs of environmental liabilities using current technology, enacted laws and regulations, industry experience gained at similar sites and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of probable cost, NW Natural records the liability at the lower end of this range. It is likely that changes in these estimates will occur throughout the remediation process for each of these sites due to uncertainty concerning NW Natural's responsibility, the complexity of environmental laws and regulations and the selection of compliance alternatives. The status of each of the sites currently under investigation is provided below.

Gasco site. NW Natural owns property in Multnomah County, Oregon that is the site of a former gas manufacturing plant that was closed in 1956 (the Gasco site). The Gasco site has been under investigation by NW Natural for environmental contamination under the Oregon Department of Environmental Quality's (ODEQ) Voluntary Clean-Up Program. In June 2003, the Company filed a Feasibility Scoping Plan and an Ecological and Human Health Risk Assessment with the ODEQ, which outlined a range of remedial alternatives for the most contaminated portion of the Gasco site. NW Natural has accrued a liability of $1.4 million for the Gasco site, which is at the low end of the range because no amount within the range is considered to be more likely than another and the high end of the range cannot be estimated.

Siltronic (formerly Wacker) site. NW Natural previously owned property adjacent to the Gasco site that now is the location of a manufacturing plant owned by Siltronic Corporation (formerly Wacker Siltronic Corporation) (the Siltronic site). In 2005, the estimated liability for this site increased due to new information regarding required additional storm-water pollution work and indoor air quality studies, resulting in an additional accrual of less than $0.1 million. The amount of the additional accrual was deferred to a regulatory asset account pursuant to an order of the OPUC (see "Regulatory and Insurance Recovery for Environmental Matters," below).

Portland Harbor site. In 1998, the ODEQ and the U.S. Environmental Protection Agency (EPA) completed a study of sediments in a 5.5-mile segment of the Willamette River (the Portland Harbor) that includes the area adjacent to the Gasco site and the Siltronic site. The Portland Harbor was listed by the EPA as a Superfund site in 2000 and the Company was notified that it is a potentially responsible party. Subsequently, the EPA approved a Programmatic Work Plan, Field Sampling Plan and Quality Assurance Project Plan for the Portland Harbor Remedial Investigation/Feasibility Study (RI/FS). NW Natural's share of the original cost estimate for the RI/FS work, which was expected to be completed in 2007, was $1.6 million. However, as a result of the EPA's indication that further study will be required, an additional accrual of $2.3 million was recorded in 2005 for the additional studies, regulatory oversight and related legal costs. Current information is not sufficient to reasonably estimate additional liabilities, if any, or the range of potential liabilities, for environmental remediation and monitoring after the RI/FS work plan is completed, except for the early action removal of a tar deposit in the river sediments discussed below.

In April 2004 the Company entered into an Administrative Order on Consent providing for early action removal of a deposit of tar in the river sediments adjacent to the Gasco site. NW Natural completed the removal of the tar deposit in the Portland Harbor in October 2005 and on Nov. 5, 2005 the EPA approved the completed project. The estimated cost for the removal, including technical work, oversight, consultants, legal fees and ongoing monitoring is $10 million. To date NW Natural has spent $7.3 million on work related to the removal of the tar deposit with a remaining liability of $2.7 million.

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

Regulatory and Insurance Recovery for Environmental Matters. In May 2003, the OPUC approved NW Natural's request for deferral of environmental costs associated with specific sites, including the Gasco, Siltronic, and Portland Harbor sites. The authorization, which was extended through January 2006 and expanded to include the Oregon Steel Mills site, allows NW Natural to defer and seek recovery of unreimbursed environmental costs in a future general rate case. An application for extension of the regulatory approval to defer environmental costs is pending. As of Dec. 31, 2005, the Company has paid a cumulative total of $12.4 million relating to the named sites since the effective date of the deferral authorization.

On a cumulative basis, NW Natural has recognized a total of $23.7 million for environmental costs, including legal, investigation, monitoring and remediation costs. Of this total, $17.3 million has been spent to-date and $6.4 million is reported as an outstanding liability. At Dec. 31, 2005, the Company had a regulatory asset of $18.8 million which includes $12.4 million of total expenditures to date and accruals for an additional estimated cost of $6.4 million. The Company believes the recovery of these costs is probable through the regulatory process. The Company also has an insurance receivable of $1.1 million, which is not included in the regulatory asset amount. The Company intends to pursue recovery of these environmental costs from its general liability insurance policies, and the regulatory asset will be reduced by the amount of any corresponding insurance recoveries. The Company considers insurance recovery of some portion of its environmental costs probable based on a combination of factors, including a review of the terms of its insurance policies, the financial condition of the insurance companies providing coverage, a review of successful claims filed by other utilities with similar gas manufacturing facilities, and recent Oregon legislation that allows an insured party to seek recovery of "all sums" from one insurance company. The Company has not filed claims for insurance recovery nor have the insurance companies approved or denied coverage of these claims.

The following table summarizes the regulatory asset and accrued liabilities relating to environmental matters at Dec. 31, 2005 and 2004.

	Regulatory Asset		Accrued Liability	
(Millions)	2005	2004	2005	2004
Gasco site	$ 3.2	$2.1	$1.4	$1.3
Siltronic site	0.3	0.2	-	0.1
Portland Harbor site	15.1	3.8	4.9	3.4
Oregon Steel Mills site	0.2	0.2	0.1	0.2
Total	$18.8	$6.3	$6.4	$5.0

Legal Proceedings

The Company is subject to claims and litigation arising in the ordinary course of business. Although the final outcome of any of these legal proceedings, including the matters described below, cannot be predicted with certainty, the Company does not expect that the ultimate disposition of these matters will have a materially adverse effect on the Company's financial condition, results of operations or cash flows.

Independent Backhoe Operator Action. Since May 2004 five lawsuits have been filed against NW Natural by 11 independent backhoe operators who performed backhoe services for the Company under contract. These five lawsuits have been consolidated into one consolidated case, Law and Zuehlke, et. al. v. Northwest Natural Gas Co., CV-04-728-KI. The consolidated case consolidates the following cases previously reported: *Kerry Law and Arnold Zuehlke, on behalf of themselves and all other similarly situated v. Northwest Natural Gas Company* (Filed May 28, 2004 U.S. Dist. Ct. D. Or. Case No. CV-04-728-KI), *Ike Whittlesey, C.G. Nick Courtney, Mark Parrish, John J. Shooter, Roger Whittlesey and Philip Courtney v. Northwest Natural* (Filed February 18, 2005 U.S. Dist. Ct. D. Or. Case No. CV-05-241-KI), *Phillip Courtney v. Northwest Natural* (Filed April 12, 2005 U.S. Dist. Ct. D. Or., Case No. CV-05-507-BR), and *Kenneth Holtmann et. al. v. Northwest Natural* (Filed May 20, 2005 U.S. Dist. Ct. D. Or. Case No. 05-CV-00724-BR). The consolidated case also includes a fifth lawsuit filed on January 23, 2006, *Larry L. Luethe v. Northwest Natural* (U.S. Dist. Ct. D. Or. Case No. CV-06-098-MO).

Plaintiffs in the consolidated case are or have been independent backhoe operators who performed services for the Company under contract. Plaintiffs allege violation of the Fair Labor Standards Act for failure to pay overtime and also assert state wage and hour claims. Plaintiffs claim that they should have been considered "employees," and seek overtime wages and interest in amounts to be determined, liquidated damages equal to the overtime award, civil penalties and attorneys' fees and costs. Additionally, with the exception of the plaintiff in *Larry L. Luethe v. Northwest Natural,* plaintiffs allege that the failure to classify them as employees constituted a breach of contract and a tort under and with respect to certain unspecified employee benefits plans, programs and agreements. With the exception of the plaintiff in *Larry L. Luethe v. Northwest Natural,* plaintiffs seek an unspecified amount of damages for the value of what they would have received under these employee benefit plans if they had been classified as employees. The Company expects that the plaintiff in *Larry L. Luethe v. Northwest Natural* will amend his complaint to include these breach of contract and tort claims for unspecified damages.

In October 2005, the court granted the Company's motion to stay plaintiffs' claims pending exhaustion of the administrative review process with regard to each of the plans under which plaintiffs allege that they would have been eligible to receive benefits. The litigation is still stayed pending plaintiffs' exhaustion of the administrative review process. There is insufficient information at this time to reasonably estimate the range of liability, if any, from these claims. NW Natural will vigorously contest these claims and does not expect the outcome of this litigation to have a material effect on its results of operations or financial condition.

Oregon Steel Mills site. In 2004, NW Natural was served with a third-party complaint by the Port of Portland (Port) in a Multnomah County Circuit Court case, *Oregon Steel Mills, Inc. v. The Port of Portland*. The Port alleges that in the 1940s and 1950s petroleum wastes generated by the Company's predecessor, Portland Gas & Coke Company, and ten other third-party defendants were disposed of in a waste oil disposal facility operated by the United States or Shaver Transportation Company on property then owned by the Port and now owned by Oregon Steel Mills. The Port's complaint seeks contribution for unspecified past remedial action costs incurred by the Port regarding the former waste oil disposal facility as well as a declaratory judgment allocating liability for future remedial action costs. In March 2005, motions to dismiss by the Company and other third-party defendants were denied on the basis that the failure of the Port to plead and prove that the Company was in violation of law was an affirmative defense that may be asserted at trial, but did not provide a sufficient basis for dismissal of the Port's claim. No date has been set for trial and discovery is ongoing. The Company has requested and received regulatory approval from the OPUC to defer and seek recovery of environmental costs related to the Oregon Steel Mills site, if any.

Industrial Customer Litigation. On Feb. 3, 2006, Georgia-Pacific Corporation filed suit against NW Natural (Georgia-Pacific Corporation v. Northwest Natural Gas Company, Case No. CV06-151-PK, United States District Court, District of Oregon), alleging that NW Natural offered to sell natural gas to Georgia-Pacific under the interruptible sales service provisions of the Company's Rate Schedule 32 at a commodity rate set at the Company's Weighted Average Cost of Gas (WACOG). Georgia-Pacific further alleged that it accepted this offer and that the Company failed to perform as promised when, in October 2005, NW Natural notified Georgia-Pacific that it would have to charge Georgia-Pacific the incremental costs of acquiring gas on the open market. Georgia-Pacific also alleges breach of contract, promissory estoppel, fraudulent misrepresentation and breach of the duty of good faith and fair dealing. As a result, Georgia-Pacific is seeking damages in an amount to be determined at trial but which they expect to be at least $235,000, plus consequential damages in an amount to be determined at trial. Georgia-Pacific further alleges that by failing to sell gas to Georgia-Pacific at the agreed upon price, NW Natural violated Oregon state laws that regulate utility operations, thereby entitling Georgia-Pacific to treble damages and attorney fees.

Prior to the Georgia-Pacific federal lawsuit being filed, on Jan. 5, 2006, NW Natural sought a declaratory judgment in the Circuit Court for the State of Oregon (NW Natural Gas Company v. Georgia-Pacific Corporation, Case No. 0601-00116, Multnomah County) declaring that, due to the rapid rise in the cost of natural gas after hurricanes Katrina and Rita, the Company acted in accordance with its tariffs and all applicable laws when it informed Georgia-Pacific that it would not sell Georgia-Pacific natural gas at its WACOG price. When Georgia-Pacific responded by filing the federal lawsuit described above, and removing the declaratory judgment action to the federal court on Feb. 2, 2006, NW Natural voluntarily dismissed its suit for declaratory relief, and now all matters between the parties are before the federal court. NW Natural will vigorously contest the claims of Georgia-Pacific.

NORTHWEST NATURAL GAS COMPANY
QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

	Quarter ended				
(Thousands, except per share amounts)	March 31	June 30	Sept. 30	Dec. 31	Total
2005					
Operating revenues	$308,777	$153,667	$106,667	$341,375	$910,486
Net operating revenues**	120,986	57,649	41,940	104,418	324,993
Net income (loss)	39,887	1,140	(8,671)	25,793	58,149
Basic earnings (loss) per share	1.45	0.04	(0.31)	0.94	2.11*
Diluted earnings (loss) per share	1.43	0.04	(0.31)	0.93	2.11*
2004					
Operating revenues	$254,450	$109,659	$ 81,441	$262,054	$707,604
Net operating revenues**	105,927	50,043	37,466	98,059	291,495
Net income (loss)	32,612	(716)	(8,285)	26,961	50,572
Basic earnings (loss) per share	1.26	(0.03)	(0.30)	0.98	1.87*
Diluted earnings (loss) per share	1.24	(0.03)	(0.30)	0.97	1.86*

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

** As of Dec. 31, 2005, revenue taxes are included in net operating revenues. Revenue taxes are expenses primarily related to utility franchise agreements and are based on gross operating revenues. Since revenue taxes are a direct cost of utility sales, these expenses were reclassified to net operating revenues. Prior periods' quarterly and annual amounts have been reclassified to conform with the current presentation, and these reclassifications did not have an impact on net income (loss).

NORTHWEST NATURAL GAS COMPANY

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

COLUMN A	COLUMN B	COLUMN C		COLUMN D	COLUMN E
		Additions		Deductions	
	Balance at beginning of period	Charged to costs and expenses	Charged to other accounts	Net write-offs	Balance at end of period
Thousands (year ended Dec. 31)					
2005					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$2,434	$3,034	$0	$2,401	$3,067
2004					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$1,763	$3,312	$0	$2,641	$2,434
2003					
Reserves deducted in balance sheet from assets to which they apply:					
Allowance for uncollectible accounts	$1,815	$1,990	$0	$2,042	$1,763

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

As of Dec. 31, 2005, the principal executive officer and principal financial officer of the Company have evaluated the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended (Exchange Act)). Based upon that evaluation, the principal executive officer and principal financial officer of the Company have concluded that such disclosure controls and procedures are effective in timely alerting them to any material information relating to the Company and its consolidated subsidiaries required to be included in the Company's reports filed with or furnished to the Securities and Exchange Commission under the Exchange Act.

(b) Changes in Internal Control Over Financial Reporting

During 2005, the Company conducted an extensive effort to analyze and assess the effectiveness of its internal controls over financial reporting. The assessments were made by management under the supervision of its chief financial officer. During the course of its assessments, the Company identified areas of internal control that warranted improvement. However, there has been no change in the Company's internal control over financial reporting that occurred during its most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

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

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

Information concerning the Company's Board of Directors, its Committees and the Audit Committee financial expert contained in the Company's definitive Proxy Statement for the May 25, 2006 Annual Meeting of Shareholders is hereby incorporated by reference.

Name	Age at Dec. 31, 2005	Positions held during last five years
Mark S. Dodson	60	President and Chief Executive Officer (2003-); President, Chief Operating Officer and General Counsel (2001-2002); Senior Vice President, Public Affairs and General Counsel (1998-2001).
Michael S. McCoy	62	Executive Vice President, Customer and Utility Operations (2000-).
David H. Anderson	44	Senior Vice President and Chief Financial Officer (2004-); Chief Financial Officer, TXU Gas Company (2004); Senior Vice President, Principal Accounting Officer and Controller (2003-2004);Vice President of Investor Relations and Shareholder Services, TXU Corp. (1997-2003).
Gregg S. Kantor	48	Senior Vice President, Public and Regulatory Affairs (2003-); Vice President, Public Affairs and Communications (1998-2002).
Margaret D. Kirkpatrick	51	Vice President and General Counsel (2005-); Partner, Stoel Rives LLP (1991- 2005).
Lea Anne Doolittle	50	Vice President, Human Resources (2000-).
Stephen P. Feltz	50	Treasurer and Controller (1999-).
C. J. Rue	60	Secretary (1982-); Assistant Treasurer (1987-).
Richelle T. Luther	37	Assistant Secretary (2002-); Associate, Stoel Rives LLP (1997-2002).

Each executive officer serves successive annual terms; present terms end May 25, 2006. There are no family relationships among the Company's executive officers.

The Company has adopted a Code of Ethics for all employees and a Financial Code of Ethics that applies to senior financial employees, both of which are available on the Company's website at www.nwnatural.com.

ITEM 11. EXECUTIVE COMPENSATION

The information concerning "Executive Compensation" contained in the Company's definitive Proxy Statement for the May 25, 2006 Annual Meeting of Shareholders is hereby incorporated by reference. Information related to Executive Officers as of Dec. 31, 2005 is reflected in Part III, Item 10, above.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth information regarding compensation plans under which equity securities of the Company are authorized for issuance as of Dec. 31, 2005 (see Note 4 to the Consolidated Financial Statements):

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by security holders:			
Long-Term Incentive Plan (LTIP) (Target Award)[1]	66,000	N/A	433,000
Restated Stock Option Plan	308,500	$29.26	1,229,800
Employee Stock Purchase Plan	32,729	$29.40	43,074
Equity compensation plans not approved by security holders:			
Executive Deferred Compensation Plan (EDCP)[2]	8,402	N/A	N/A
Directors Deferred Compensation Plan (DDCP)[2]	80,158	N/A	N/A
Deferred Compensation Plan for Directors and Executives (DCP)[3]	8,433	N/A	N/A
Non-Employee Directors Stock Compensation Plan[4]	N/A	N/A	N/A
Total	504,222		1,705,874

The information captioned "Beneficial Ownership of Common Stock by Directors and Executive Officers" contained in the Company's definitive Proxy Statement for the May 25, 2006 Annual Meeting of Shareholders is incorporated herein by reference.

[1] Shares issued pursuant to the LTIP do not include an exercise price, but are payable by the Company when the award criteria are satisfied. If the maximum awards were paid pursuant to the performance-based awards outstanding at Dec. 31, 2005, the number of shares shown in column (a) would increase by 62,000 shares and the number of shares shown in column (c) would decrease by 62,000 shares.

[2] Prior to Jan. 1, 2005, deferred amounts were credited, at the participant's election, to either a "cash account" or a Company "stock account." If deferred amounts were credited to stock accounts, such accounts were credited with a number of shares based on the purchase price of the Common Stock on the next purchase date under the Company's Dividend Reinvestment and Direct Stock Purchase Plan, and such accounts were credited with additional shares based on the deemed reinvestment of dividends. 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. The Company has contributed Common Stock to the trustee of the Umbrella Trust such that the Umbrella Trust holds the number of shares of Common Stock equal to the number of shares credited to all participants' stock accounts.

3 Effective Jan. 1, 2005, the EDCP and DDCP were replaced by the Deferred Compensation Plan for Directors and Executives (DCP). The DCP continues the basic provisions of the EDCP and DDCP under which deferred amounts are credited to either a "cash account" or a Company "stock account." Stock accounts represent a right to receive shares of Company Common Stock on a deferred basis, and such accounts are 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. The crediting rate is subject to a six percent minimum rate. The Company's obligation to pay deferred compensation in accordance with the terms of the DCP will generally become due on retirement, death, or other termination of service, and will be paid in a lump sum or in installments of five or ten years as elected by the participant in accordance with the terms of the DCP. The right of each participant in the DCP is that of a general, unsecured creditor of the Company.

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

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information captioned "Certain Relationships and Related Transactions" in the Company's definitive Proxy Statement for the May 25, 2006 Annual Meeting of Shareholders is hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information captioned "2005 and 2004 Audit Firm Fees" in the Company's definitive Proxy Statement for the May 25, 2006 Annual Meeting of Shareholders is hereby incorporated by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

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

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

2. List of Exhibits filed:

Reference is made to the Exhibit Index commencing on page 111.

SIGNATURES

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

NORTHWEST NATURAL GAS COMPANY

Date: March 1, 2006

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

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

SIGNATURE	TITLE	DATE
/s/ Mark S. Dodson Mark S. Dodson, President and Chief Executive Officer	Principal Executive Officer and Director	March 1, 2006
/s/ David H. Anderson David H. Anderson Senior Vice President and Chief Financial Officer	Principal Financial Officer	March 1, 2006
/s/ Stephen P. Feltz Stephen P. Feltz Treasurer and Controller	Principal Accounting Officer	March 1, 2006
/s/ Timothy P. Boyle Timothy P. Boyle	Director	
Martha L. Byorum	Director	
/s/ John D. Carter John D. Carter	Director	
/s/ C. Scott Gibson C. Scott Gibson	Director	
/s/ Tod R. Hamachek Tod R. Hamachek	Director	
/s/ Randall C. Papé Randall C. Papé	Director	March 1, 2006
/s/ Richard G. Reiten Richard G. Reiten	Director	
/s/ Kenneth Thrasher Kenneth Thrasher	Director	
/s/ Russell F. Tromley Russell F. Tromley	Director	
/s/ Richard L. Woolworth Richard L. Woolworth	Director	

EXHIBIT INDEX
To
Annual Report on Form 10-K
For Fiscal Year Ended
Dec. 31, 2005

Exhibit Number	Document
*3a.	Restated Articles of Incorporation, as filed and effective June 24, 1988 and amended December 8, 1992, December 1, 1993 and May 27, 1994 (incorporated herein by reference to Exhibit 3a. to Form 10-K for 1994, File No. 0-994).
*3b.	Bylaws as amended July 22, 2004 (incorporated herein by reference to Exhibit 3 to Form 10-Q for quarter ended June 30, 2004, File No. 1-15973.
*4a.	Copy of Mortgage and Deed of Trust, dated as of July 1, 1946, to Bankers Trust and R. G. Page (to whom Stanley Burg is now successor), Trustees (incorporated herein by reference to Exhibit 7(j) in File No. 2-6494); and copies of Supplemental Indentures Nos. 1 through 14 to the Mortgage and Deed of Trust, dated respectively, as of June 1, 1949, March 1, 1954, April 1, 1956, February 1, 1959, July 1, 1961, January 1, 1964, March 1, 1966, December 1, 1969, April 1, 1971, January 1, 1975, December 1, 1975, July 1, 1981, June 1, 1985 and November 1, 1985 (incorporated herein by reference to Exhibit 4(d) in File No. 33-1929); Supplemental Indenture No. 15 to the Mortgage and Deed of Trust, dated as of July 1, 1986 (filed as Exhibit 4(c) in File No. 33-24168); Supplemental Indentures Nos. 16, 17 and 18 to the Mortgage and Deed of Trust, dated, respectively, as of November 1, 1988, October 1, 1989 and July 1, 1990 (incorporated herein by reference to Exhibit 4(c) in File No. 33-40482); Supplemental Indenture No. 19 to the Mortgage and Deed of Trust, dated as of June 1, 1991 (incorporated herein by reference to Exhibit 4(c) in File No. 33-64014); and Supplemental Indenture No. 20 to the Mortgage and Deed of Trust, dated as of June 1, 1993 (incorporated herein by reference to Exhibit 4(c) in File No. 33-53795).
*4d.	Copy of Indenture, dated as of June 1, 1991, between the Company and Bankers Trust Company, Trustee, relating to the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4(e) in File No. 33-64014).
*4e.	Officers' Certificate dated June 12, 1991 creating Series A of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4e. to Form 10-K for 1993, File No. 0-994).
*4f.	Officers' Certificate dated June 18, 1993 creating Series B of the Company's Unsecured Medium-Term Notes (incorporated herein by reference to Exhibit 4f. to Form 10-K for 1993, File No. 0-994).

*4f.(1) Officers' Certificate dated January 17, 2003 relating to Series B of the Company's Unsecured Medium-Term Notes and supplementing the Officers' Certificate dated June 18, 1993 (incorporated herein by reference to Exhibit 4f.(1) to Form 10-K for 2002, File No. 0-994).

*4g. Rights Agreement, dated as of February 27, 1996, between the Company and Boatmen's Trust Company (American Stock Transfer & Trust Company, successor), which includes as Exhibit A thereto the form of a Right Certificate and as Exhibit B thereto the Summary of Rights to Purchase Common Shares (incorporated herein by reference to Exhibit 1 to Form 8-A, dated February 27, 1996, File No. 0-994).

*4h. Amendment No. 1, dated October 5, 2001, to Rights Agreement, dated February 27, 1996, between the Company and Boatmen's Trust Company (American Stock Transfer & Trust Company, successor) (incorporated herein by reference to Exhibit 4 to Form 10-Q for quarter ended September 30, 2001, File No. 0-994).

*4i. Form of Credit Agreement between Northwest Natural Gas Company and each of JPMorgan Chase Bank, NA, U.S. Bank National Association, Bank of America, NA, Wells Fargo Bank, NA and Wachovia Bank, National Association, dated as of October 1, 2005, including Form of Note (incorporated herein by reference to Exhibit 10.1 to Form 10-Q dated November 3, 2005, File No. 1-15973).

*4j. Distribution Agreement, dated September 28, 2004, among the Company, Merrill Lynch, Pierce Fenner & Smith Incorporated, UBS Securities LLC, J.P. Morgan Securities Inc. and Piper Jaffray & Co. (incorporated herein by reference to Exhibit 1.1 to Form 8-K dated October 4, 2004, File No. 1-15973).

*4k. Form of Secured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.1 to Form 8-K dated October 4, 2004, File No. 1-15973).

*4l. Form of Unsecured Medium-Term Notes, Series B (incorporated herein by reference to Exhibit 4.2 to Form 8-K dated October 4, 2004, File No. 1-15973).

*10j. Transportation Agreement, dated June 29, 1990, between the Company and Northwest Pipeline Corporation (incorporated herein by reference to Exhibit 10j. to Form 10-K for 1993, File No. 0-994).

*10j.(1) Replacement Firm Transportation Agreement, dated July 31, 1991, between the Company and Northwest Pipeline Corporation (incorporated herein by reference to Exhibit 10j.(2) to Form 10-K for 1992, File No. 0-994).

*10j.(2) Firm Transportation Service Agreement, dated November 10, 1993, between the Company and Pacific Gas Transmission Company (incorporated herein by reference to Exhibit 10j.(2) to Form 10-K for 1993, File No. 0-994).

*10j.(3)	Service Agreement, dated June 17, 1993, between Northwest Pipeline Corporation and the Company (incorporated herein by reference to Exhibit 10j.(3) to Form 10-K for 1994, File No. 0-994).
*10j.(5)	Firm Transportation Service Agreement, dated June 22, 1994, between Pacific Gas Transmission Company and the Company (incorporated herein by reference to Exhibit 10j.(5) to Form 10-K for 1995, File No. 0-994).
*10j.(6)	Firm Service Agreement between the Company and Westcoast Energy Inc., dated as of April 1, 2003 (incorporated herein by reference to Exhibit 10 to Form 10-Q for quarter ended March 31, 2003, File No. 0-994).
11	Statement re computation of per share earnings.
12	Statement re computation of ratios of earnings to fixed charges.
23	Consent of PricewaterhouseCoopers LLP.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15-d-14(a), Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

Executive Compensation Plans and Arrangements:

*10b.	Executive Supplemental Retirement Income Plan (2004 Restatement) (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated September 28, 2004, File No. 1-15973).
*10b.(1)	Supplemental Executive Retirement Plan, effective September 1, 2004 (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 20, 2004, File No. 1-15973).
*10b.(2)	Northwest Natural Gas Company Supplemental Trust, effective January 1, 2005, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.7 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10b.(3)	Northwest Natural Gas Company Umbrella Trust for Directors, effective January 1, 1991, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.5 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10b.(4)	Northwest Natural Gas Company Umbrella Trust for Executives, effective January 1, 1988, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.6 to Form 8-K dated December 16, 2005, File No. 1-15973).
* 10c.	Restated Stock Option Plan, as amended effective May 23, 2002 (incorporated herein by reference to Exhibit 10(a) to Form 10-Q for quarter ended September 30, 2002, File No. 0-994).
*10c.(1)	Form of Restated Stock Option Plan Agreement (incorporated herein by reference to Exhibit 10.3 to Form 10-Q dated November 3, 2005, File No. 1-15973).

*10e.	Executive Deferred Compensation Plan, effective as of January 1, 1987, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.4 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10f.	Directors Deferred Compensation Plan, effective June 1, 1981, restated as of December 15, 2005 (incorporated herein by reference to Exhibit 10.3 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10f.(1)	Deferred Compensation Plan for Directors and Executives effective January 1, 2005 (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated November 17, 2004, File No. 1-15973).
*10g.	Form of Indemnity Agreement as entered into between the Company and each director and executive officer (incorporated herein by reference to Exhibit 10g. to Form 10-K for 1988, File No. 0-994).
*10i.	Non-Employee Directors Stock Compensation Plan, as amended effective December 15, 2005 (incorporated herein by reference to Exhibit 10.2 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10i-1	Summary of waiver of forfeiture provisions of Non-Employee Directors Stock Compensation Plan for a deceased director (incorporated herein by reference to Exhibit 10i-1 to Form 10-K for 2004, File No. 1-15973).
*10k.	Executive Annual Incentive Plan, effective January 1, 2003 (incorporated herein by reference to Exhibit 10 k. to Form 10-K for 2002, File No. 0-994)
*10n.	Summary of Compensation Arrangements for Chairman of the Board, March 1, 2003 – February 28, 2005 (incorporated herein by reference to Exhibit 10n.-3 to Form 10-K for 2002, File No. 0-994).
*10o.	Form of amended and restated executive change in control severance agreement between the Company and each executive officer (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10p.	Employment Agreement dated July 2, 1997, between the Company and an executive officer (incorporated herein by reference to Exhibit 10(a) for Form 10-Q for the quarter ended September 30, 1997, File No. 0-994).
*10p.-1	Amendment dated December 18, 1997 to employment agreement dated July 2, 1997, between the Company and an executive officer (incorporated herein by reference to Exhibit 10p.-1 to Form 10-K for 1997, File No. 0-994).
*10p.-2	Amendment dated September 24, 1998 to employment agreement dated July 2, 1997, as previously amended, between the Company and an executive officer (incorporated herein by reference to Exhibit 10(g) to Form 10-Q for the quarter ended September 30, 1998, File No. 0-994).
*10p.-3	Employment Agreement dated December 20, 2002, between the Company and an executive officer (incorporated herein by reference to Exhibit 10p.-3 to Form 10-K for 2002, File No. 0-994).

*10r.	Employment agreement dated May 11, 1999, between the Company and an executive officer (incorporated herein by reference to Exhibit 10 to Form 10-Q for the quarter ended June 30, 1999, File No. 0-994).
*10v.	Northwest Natural Gas Company Long-Term Incentive Plan, as amended and restated effective July 26, 2001 (incorporated herein by reference to Exhibit 10(c) to Form 10-Q for the quarter ended June 30, 2001, File No. 0-994).
*10w.	Form of Long-Term Incentive Award Agreement under the Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.8 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10x.	Form of Restricted Stock Bonus Agreement under the Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.9 to Form 8-K dated December 16, 2005, File No. 1-15973).
*10y.(1)	Retirement Agreement and Mutual Release of All Claims dated June 25, 2004 entered into between a former executive officer and the Company (incorporated herein by reference to Exhibit 10 to Form 10-Q for the quarter ended June 30, 2004, File No. 1-15973).
*10y.(2)	Amendment to Retirement Agreement and Mutual Release of All Claims between a former executive officer and the Company dated October 19, 2004 (incorporated herein by reference to Exhibit 10 to Form 10-Q for the quarter ended September 30, 2004, File No. 1-15973).
*10z.(1)	Summary of non-employee director compensation, effective January 1, 2005 (incorporated herein by reference to Exhibit 10.1 to Form 8-K dated Feb. 11, 2005, File No. 1-15973).

The Company agrees to furnish the Commission, upon request, a copy of certain instruments defining rights of holders of long-term debt of the Company or its consolidated subsidiaries which authorize securities thereunder in amounts which do not exceed 10% of the total assets of the Company.

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*Incorporated herein by reference as indicated

EXHIBIT 11

NORTHWEST NATURAL GAS COMPANY
Statement Re: Computation of Per Share Earnings
(Thousands, except per share amounts)
(Unaudited)

	12 Months Ended December 31,		
	2005	2004	2003
Net income	$58,149	$50,572	$45,983
Redeemable preferred stock dividend requirements	—	—	294
Earnings applicable to common stock – basic	58,149	50,572	45,689
Debenture interest less taxes	—	200	257
Net income - diluted	$58,149	$50,772	$45,946
Average common shares outstanding – basic	27,564	27,016	25,741
Stock options	57	40	28
Convertible debentures	—	227	292
Average common shares outstanding – diluted	27,621	27,283	26,061
Earnings per share of common stock - basic	$ 2.11	$ 1.87	$ 1.77
Earnings per share of common stock – diluted	$ 2.11	$ 1.86	$ 1.76

For the years ended Dec. 31, 2005, 2004 and 2003, 6,000 shares, 201,800 shares and 77,500 shares, respectively, were excluded from the calculation of diluted earnings per share because the effect would have been antidilutive.

EXHIBIT 12

NORTHWEST NATURAL GAS COMPANY
Computation of Ratio of Earnings to Fixed Charges
January 1, 2001 - Dec 31, 2005
(Thousands, except ratio of earnings to fixed charges)
(Unaudited)

	Year Ended December 31				
	2005	2004	2003	2002	2001
Fixed Charges, as Defined:					
Interest on Long-Term Debt	$ 34,330	$ 33,776	$ 33,258	$ 32,264	$ 30,224
Other Interest	2,665	2,184	2,048	1,620	3,772
Amortization of Debt Discount and Expense	808	773	696	799	768
Interest Portion of Rentals	1,357	1,489	1,622	1,578	1,572
Total Fixed Charges, as defined	$ 39,160	$ 38,222	$ 37,624	$ 36,261	$ 36,336
Earnings, as Defined:					
Net Income	$ 58,149	$ 50,572	$ 45,983	$ 43,792	$ 50,187
Taxes on Income	32,720	26,531	23,340	23,444	27,553
Fixed Charges, as above	39,160	38,222	37,624	36,261	36,336
Total Earnings, as defined	$130,029	$115,325	$106,947	$103,497	$114,076
Ratio of Earnings to Fixed Charges	3.32	3.02	2.84	2.85	3.14

EXHIBIT 23

Consent of Independent Registered Public Accounting Firm

We hereby consent to the incorporation by reference in the Registration Statements on Form S-8 (Nos. 33-63017, 333-46430, 333-55002, 333-70218, 333-100885, and 333-120955, and Post-Effective Amendment No. 1 to Registration Statement No. 2-76276) and in the Registration Statements on Form S-3 (Nos. 33-53795, 333-112604, and 333-123898, and Post-Effective Amendment No. 1 to Registration Statement Nos. 33-1304 and 33-20384) of Northwest Natural Gas Company of our report dated February 28, 2006 relating to the consolidated financial statements, financial statement schedule, management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/ PricewaterhouseCoopers LLP

Portland, Oregon
March 1, 2006

EXHIBIT 31.1

CERTIFICATION

I, Mark S. Dodson, certify that:

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

Date: March 1, 2006

/s/ Mark S. Dodson

Mark S. Dodson
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, David H. Anderson, certify that:

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

Date: March 1, 2006

/s/ David H. Anderson

David H. Anderson
Senior Vice President and Chief Financial Officer

EXHIBIT 32.1

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

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

1. Our Annual Report on Form 10-K for the year ended December 31, 2005 (the Report) fully complies with the requirements of section 13(a) of the Securities Exchange Act of 1934, as amended; and

2. Information contained in the Report fairly presents, in all material respects, the financial condition and results of operation of the Company.

IN WITNESS WHEREOF, each of the undersigned has caused this instrument to be executed this 1st day of March 2006.

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

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

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

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Design Avive Design **Feature Photography** Iridio Photography **Portrait/Shareholder Letter, Shareholder Feature, Board & Officers** Bruce Beaton Photography
Production/Printing RR Donnelley Premedia Technologies Printed on recycled stock

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