e-FILING REPORT COVER SHEET

Send completed Cover Sheet and the Report in an email addressed to:
PUC.FilingCenter@state.or.us

REPORT NAME: Annual Report (FERC Form No. 2), Oregon Supplement, Annual Report to Stock

COMPANY NAME: Cascade Natural Gas Corporation

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes

If yes, please submit only the cover letter electronically. Submit confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

If known, please select designation: ☐ RE (Electric) ☒ RG (Gas) ☐ RW (Water) ☐ RO (Other)

Report is required by: ☒ OAR 860-027-0070
☐ Statute
☐ Order
☐ Other

Is this report associated with a specific docket/case? ☒ No ☐ Yes

If yes, enter docket number: Enter Docket number

List applicable Key Words for this report to facilitate electronic search:
Enter Key Words

DO NOT electronically file with the PUC Filing Center:

- Annual Fee Statement form and payment remittance or
- OUS or RSPF Surcharge form or surcharge remittance or
- Any other Telecommunications Reporting or
- Any daily safety or safety incident reports or
- Accident reports required by ORS 654.715

Please file the above reports according to their individual instructions.

THIS FILING IS		
Item 1: ☒ An Initial (Original) Submission	OR ☐	Resubmission No. ____

Form 2 Approved
OMB No.1902-0028
(Expires 10/31/2014)

Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
Cascade Natural Gas Corporation	End of 2012

INSTRUCTIONS FOR FILING FERC FORMS 2, 2-A and 3-Q

GENERAL INFORMATION

I Purpose

FERC Forms 2, 2-A, and 3-Q are designed to collect financial and operational information form natural gas companies subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a non-confidential public use forms.

II. Who Must Submit

Each natural gas company whose combined gas transported or stored for a fee exceed 50 million dekatherms in each of the previous three years must submit FERC Form 2 and 3-Q.

Each natural gas company not meeting the filing threshold for FERC Form 2, but having total gas sales or volume transactions exceeding 200,000 dekatherms in each of the previous three calendar years must submit FERC Form 2-A and 3-Q.

Newly established entities must use projected data to determine whether they must file the FERC Form 3-Q and FERC Form 2 or 2-A.

III. What and Where to Submit

(a) Submit Forms 2, 2-A and 3-Q electronically through the submission software at http://www.ferc.gov/docs-filing/eforms/form-2/elec-subm-soft.asp .

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Form 2 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mailing two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Form 2, Page 3, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared. Unless eFiling the Annual Report to Stockholders, mail these reports to the Secretary of the Commission at:

Secretary of the Commission
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the Annual CPA certification, submit with the original submission of this form, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984) prepared in conformity with the current standards of reporting which will:

(i) Contain a paragraph attesting to the conformity, in all material respects, of the schedules listed below with the Commission's applicable Uniform Systems of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

(ii) be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 158.10-158.12 for specific qualifications.)

Reference	Reference Schedules Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

Filers should state in the letter or report, which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist
.

(e) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders" and "CPA Certification Statement," have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission website at http://www.ferc.gov/help/how-to.asp

(f) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 2 and 2-A free of charge from: http://www.ferc.gov/docs-filing/eforms/form-2/form-2.pdf and http://www.ferc.gov/docs-filing/eforms/form-2a/form-2a.pdf, respectively. Copies may also be obtained from the Public Reference and Files Maintenance Branch, Federal Energy Regulatory Commission, 888 First Street, NE. Room 2A, Washington, DC 20426 or by calling (202).502-8371

IV. When to Submit:

FERC Forms 2, 2-A, and 3-Q must be filed by the dates:

(a) FERC Form 2 and 2-A --- by April 18th of the following year (18 C.F.R. §§ 260.1 and 260.2)

(b) FERC Form 3-Q --- Natural gas companies that file a FERC Form 2 must file the FERC Form 3-Q within 60 days after the reporting quarter (18 C.F.R.§ 260.300), and

(c) FERC Form 3-Q --- Natural gas companies that file a FERC Form 2-A must file the FERC Form 3-Q within 70 days after the reporting quarter (18 C.F.R. § 260.300).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the Form 2 collection of information is estimated to average 1,623 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the Form 2A collection of information is estimated to average 250 hours per response. The public reporting burden for the Form 3-Q collection of information is estimated to average 165 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare all reports in conformity with the Uniform System of Accounts (USofA) (18 C.F.R. Part 201). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or Dth) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions**.

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Footnote and further explain accounts or pages as necessary.

IX. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

X. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

XI. Report all gas volumes in Dth unless the schedule specifically requires the reporting in another unit of measurement.

DEFINITIONS

I. Btu per cubic foot – The total heating value, expressed in Btu, produced by the combustion, at constant pressure, of the amount of the gas which would occupy a volume of 1 cubic foot at a temperature of 60°F if saturated with water vapor and under a pressure equivalent to that of 30°F, and under standard gravitational force (980.665 cm. per sec) with air of the same temperature and pressure as the gas, when the products of combustion are cooled to the initial temperature of gas and air when the water formed by combustion is condensed to the liquid state (called gross heating value or total heating value).

II. Commission Authorization -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

III. Dekatherm – A unit of heating value equivalent to 10 therms or 1,000,000 Btu.

IV Respondent – The person, corporation, licensee, agency, authority, or other legal entity or instrumentality on whose behalf the report is made.

EXCERPTS FROM THE LAW
(Natural Gas Act, 15 U.S.C. 717-717w)

"Sec. 10(a). Every natural-gas company shall file with the Commission such annual and other periodic or special reports as the Commission may by rules and regulations or order prescribe as necessary or appropriate to assist the Commission in the proper administration of this act. The Commission may prescribe the manner and form in which such reports shall be made and require from such natural-gas companies specific answers to all questions upon which the Commission may need information. The Commission may require that such reports include, among other things, full information as to assets and liabilities, capitalization, investment and reduction thereof, gross receipts, interest dues and paid, depreciation, amortization, and other reserves, cost of facilities, costs of maintenance and operation of facilities for the production, transportation, delivery, use, or sale of natural gas, costs of renewal and replacement of such facilities, transportation, delivery, use and sale of natural gas..."

"Section 16. The Commission shall have power to perform all and any acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this act; and may prescribe the form or forms of all statements declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and time within they shall be filed..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. See NGA § 22(a), 15 U.S.C. § 717t-1(a).

QUARTERLY/ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

IDENTIFICATION		
01 Exact Legal Name of Respondent ***Cascade Natural Gas Corporation***	02 Year of Report End of ***December 31, 2012***	
03 Previous Name and Date of Change (If name changed during year) ***Not applicable***		
04 Address of Principal Office at End of Year (Street, City, State, Zip Code) ***8113 West Grandridge Boulevard, Kennewick, Washington 99336-7166***		
05 Name of Contact Person ***Tammy Nygard***	06 Title of Contact Person **Director, Accounting & Finance**	
07 Address of Contact Person (Street, City, State, Zip Code) ***8113 West Grandridge Boulevard, Kennewick, Washington 99336-7166***		
08 Telephone of Contact Person, Including Area Code ***(509) 734-4516***	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	10 Date of Report (Mo, Da, Yr) ***December 31, 2012***

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

11 Name ***Tammy Nygard***	12 Title **Director, Accounting & Finance**
13 Signature Tammy Nygard	14 Date Signed 3-22-13

Title 18, U.S.C. 1001, makes it a crime for any person knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

LIST OF SCHEDULES (Natural Gas Company)

Enter in column (d) the terms "none", "not applicable", or "NA" as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the responses are "none", "not applicable", or "NA.

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

LIST OF SCHEDULES (Natural Gas Company)

Enter in column (d) the terms "none", "not applicable", or "NA" as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the responses are "none", "not applicable", or "NA.

Line No.	Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remark (d)
38	Unamortized Loss and Gain on Reacquired Debt	260		
39	Reconciliation of Reported Net Income with Taxable Income for Federal Income Taxes	261		
40	Taxes Accrued, Prepaid and Charged during the Year	262-263		
41	Miscellaneous Current and Accrued Liabilities	268		
42	Other Deferred Credits	269		
43	Accumulated Deferred Income Taxes - Other Property	274-275		
44	Accumulated Deferred Income Taxes - Other	276-277		
45	Other Regulatory Liabilities	278		
	INCOME ACCOUNT SUPPORTING SCHEDULES			
46	Monthly Quantity & Revenue Data by Rate Schedule	299		
47	Gas Operating Revenues	300-301		
48	Revenues from Transporation of Gas of Others Through Gathering Facilities	302-303		None
49	Revenues from Transporation of Gas of Others Through Transmission Facilities	304-305		None
50	Revenues from Storing Gas of Others	306-307		None
51	Other Gas Revenues	308		
52	Discounted Rate Services and Negotiated Rate Services	313		
53	Gas Operation and Maintenance Expenses	317-325		
54	Exchange and Imbalance Transactions	328		None
55	Gas Used in Utility Operations	331		
56	Transmission and Compression of Gas by Others	332		None
57	Other Gas Supply Expenses	334		None
58	Miscellaneous General Expenses-Gas	335		
59	Depreciation, Depletion and Amortization of Gas Plant	336-338		
60	Particulars Concerning Certain Income Deductions and Interest Charges Accounts	340		
	COMMON SECTION			
61	Regulatory Commission Expenses	350-351		
62	Employee Pensions and Benefits (Account 926)	352		
63	Distribution of Salaries and Wages	354-355		
64	Charges for Outside Professional and Other Consultative Services	357		
65	Transactions with Associated (Affiliated Companies)	358		
	GAS PLANT STATISTICAL DATA			
66	Compressor Stations	508-509		
67	Gas Storage Projects	512-513		
68	Transmission Lines	514		None
69	Transmission System Peak Deliveries	518		None
70	Auxiliary Peaking Facilities	519		None
71	Gas Account - Natural Gas	520		
72	Shipper Supplied Gas for the Current Quarter	521		
73	System Map	522		
74	Footnote Reference	551		None
75	Footnote Text	552		None
76	Stockholders' Reports (check appropriate box)			
	[X] Four Copies will be submitted [ ] No annual report to stockholders is prepared			

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

GENERAL INFORMATION

1. Provide the name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where general corporate books are kept.

Tammy Nygard
Manager, Accounting & Finance

8113 West Grandridge Boulevard,
Kennewick, Washington 99336-7166

2. Provide the name of the state under the laws which respondent is incorporated, and the date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

Incorporated in the State of Washington - January 2, 1953

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trustee was created, and (d) date when possession by receiver or trustee ceased.

Not applicable

4. State the classes of utility and other services furnished by respondent during the year in each state in which the respondent operated.

Natural gas distribution in the states of Washington and Oregon

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) ☐ Yes… Enter the date when such independent accountant was initially engage:

(2) ☒ No

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

CONTROL OVER RESPONDENT

1. Report in column (a) the names of all corporations, partnerships, business trusts, and similar organizations that directly, indirectly, or jointly held control (see page 103 for definition of control) over the respondent at the end of the year. If control is in a holding company organization, report in a footnote the chain of organization.
2. If control is held by trustee, state in a footnote the names of trustees, the names of beneficiaries for whom the trust is maintained, and the purpose of the trust.
3. In column (b) designate type of control over the respondent. Report an "M" if the company is the main parent or controlling company having ultimate control over the respondent. Otherwise, report a "D" for direct, an "I" for indirect, or a "J" for joint control.

Line No.	Company Name (a)	Type of Control (b)	State of Incorporation (c)	Percent Voting Stock Owned (d)
1	MDU Resources Group, Inc. (MDUR)	M	Delaware	100%
2	MDU Energy Capital, LLC	I	Delaware	100%
3	Prairie Cascade Energy Holdings, LLC (PCEH)	D	Delaware	100%
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Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

Corporations Controlled by Respondent

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.
4. In column (b) designate type of control of the respondent as "D" for direct, and "I" for indirect, or a "J" for joint control.

DEFINITIONS

1. See the Uniform System of Accounts for definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Type of Control (b)	Kind of Business (c)	Percent Voting Stock Owned (d)	Footnote Reference (e)
1	CGC Resources, Inc.	D	Pipeline Capacity Management	100%	
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Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

SECURITY HOLDERS AND VOTING POWERS

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes that each could cast on that date if a meeting were held . If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the company did not close the stock book or did not compile a list of stockholders within one year prior to the end of the year, or if since it compiled the previous list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.
2. If any security other than stock carries voting rights, explain in a supplemental statement how such security became vested with voting rights and give other important details concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.
3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.
4. Furnish details concerning any options, warranties, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants or rights. Specify the amount of such securities or assets any officer, director, associated company, or any of the 10 largest security holders is entitled to purchase. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants.

1. Give date of the latest closing of the stock book prior to end of year, and state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy.	3. Give the date and place of such meeting:
	Total:	
	By Proxy: N/A	N/A

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES 4. Number of votes as of (date): Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
5	TOTAL votes of all voting securities	1,000	1,000		
6	TOTAL number of security holders	1	1		
7	TOTAL votes of security holders	1,000	1,000		
8	listed below:				
9					
10					
11	Cascade is a wholly-owned subsidiary of MDU Resources Group, Inc.				
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Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

IMPORTANT CHANGES DURING THE YEAR

Give details concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Answer each inquiry. Enter "none" or "not applicable" where applicable. If the answer is given elsewhere in the report, refer to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration and state from whom the franchise rights were acquired. If the franchise rights were acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Briefly describe the property, and the related transactions, and cite Commission authorization, if any was required. Give date journal entries called for by Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other conditions. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and cite Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service.
Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred or assumed by respondent as guarantor for the performance by another of any agreement or obligation, including ordinary commercial paper maturing on demand or not later than one year after date of issue: State on behalf of whom the obligation was assumed and amount of the obligation. Cite Commission authorization if any was required.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. Estimated increase or decrease in annual revenues caused by important rate changes: State effective date and approximate amount of increase or decrease for each revenue classification. State the number of customers affected.
12. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
13. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

Name of Respondent This Report is:

1	None
2	None
3	None
4	None
5	None
6	None
7	None
8	Wages for hourly employees increased by 3.0% in April 2012.
9	None
10	None
11	None
12	Scott W. Madison title changed from VP, CAO, & Assistant Treasurer to VP, Regulatory Affairs, CAO, Assistant Treasurer & Assistant Secretary.
13	

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[Next page is 110]

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	737,323,182	702,854,763
3	Construction Work in Progress (107)	200-201	17,556,051	15,114,040
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	**754,879,233**	**717,968,803**
5	(Less) Accum. Provision for Depr., Amort. Depl. (108, 111, 115)		(372,642,118)	(355,227,629)
6	Net Utility Plant (Total of line 4 less 5)		**382,237,115**	**362,741,174**
7	Nuclear Fuel (120.1-120.4, and 120.6)		0	0
8	(Less) Accum. Provision for Amort., of Nucl. Fuel Assem. (120.5)		0	0
9	Nuclear Fuel (Enter Total of line 7 less 8)		-	-
10	Net Utility Plant (Total of lines 6 and 9)		**382,237,115**	**362,741,174**
11	Utility Plant Adjustments (116)	122		
12	Gas Stored-Base Gas (117.1)	220		
13	System Balancing Gas (117.2)	220		
14	Gas Stored in Reservoirs and Pipelines-Noncurrent (117.3)	220		
15	Gas Owed to System Gas (117.4)	220		
16	**OTHER PROPERTY AND INVESTMENTS**			
17	Nonutility Property (121)		202,030	202,030
18	(Less) Accum. Provision for Depreciation and Amortization (122)			
19	Investments in Associated Companies (123)	222-223		
20	Investment in Subsidiary Companies (123.1)	224-225		
21	(For Cost of Account 123.1, See Footnote Page 224, line 40)			
22	Noncurrent Portion of Allowances			
23	Other Investments (124)	222-223	9,739,905	9,479,236
24	Sinking Funds (125)			
25	Depreciation Fund (126)			
26	Amortization Fund - Federal (127)			
27	Other Special Funds (128)			
28	Long-Term Portion of Derivative Assets (175)			
29	Long-Term Portion of Derivative Assets - Hedges (176)			
30	TOTAL Other Property & Investments (Total of lines 17-20, 22-29)		**9,941,935**	**9,681,267**
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)		418,834	29,029,983
33	Speical Deposits (132-134)			350,000
34	Working Funds (135)		2,800	2,950
35	Temporary Cash Investments (136)	222-223		
36	Notes Receivable (141)		112,752	7,573,692
37	Customer Accounts Receivable (142)		9,183,809	16,479,418
38	Other Accounts Receivable (143)		1,320,446	2,556,747
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		(697,075)	(561,058)
40	Notes Receivable from Associated Companies (145)			
41	Accounts Receivable from Associated Companies (146)		60,314	17,010
42	Fuel Stock (151)			
43	Fuel Stock Expenses Undistributed (152)			

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) (continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
44	Residuals (Elec) and Extracted 44 Products (Gas) (153)			
45	Plant Materials and Operating Supplies (154)		5,943,723	5,925,620
46	Merchandise (155)			
47	Other Materials and Supplies (156)			
48	Nuclear Materials Held for Sale (157)			
49	Allowances (158.1 and 158.2)			
50	(Less) Noncurrent Portion of Allowances			
51	Stores Expense Undistributed (163)			
52	Gas Stored Underground-Current (164.1)	220		3,681,969
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220	3,166,527	3,166,527
54	Prepayments (165)	230	4,618,893	4,165,579
55	Advances for Gas (166 thru 167)			
56	Interest and Dividends Receivable (171)			
57	Rents Receivable (172)			
58	Accrued Utility Revenues (173)		23,485,734	27,419,077
59	Miscellaneous Current and Accrued Assets (174)			
60	Derivative Instrument Assets (175)			
61	(Less) Long-Term Portion of Derivative Instrument Assets (175)			
62	Derivative Instrument Assets - Hedges (176)			
63	(Less) Long-Term Portion of Derivative Instrument Assests - Hedges (176)			
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)		**47,616,757**	**99,807,515**
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)		1,927,485	2,048,113
67	Extraordinary Property Losses (182.1)	230		
68	Unrecovered Plant and Regulatory Study Costs (182.2)	230		
69	Other Regulatory Assets (182.3)	232	55,900,905	54,822,091
70	Preliminary Survey and Investigation Charges (Electric)(183)			
71	Preliminary Survey and Investigation Charges (Gas)(183.1 and 183.2)			
72	Clearing Accounts (184)		(102,840)	(83,050)
73	Temporary Facilities (185)			
74	Miscellaneous Deferred Debits (186)	233	21,172,748	14,567,743
75	Deferred Losses from Disposition of Utility Plant (187)			
76	Research, Development, and Demonstration Expend. (188)			
77	Unamortized Loss on Reacquired Debt (189)		1,016,943	1,265,997
78	Accumulated Deferred Income Taxes (190)	234-235	27,838,248	24,456,261
79	Unrecovered Purchased Gas Costs (191)			
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		107,753,489	97,077,155
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		**547,549,296**	**569,307,111**

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

COMPARATIVE BALANCE SHEET (Liabilities and Other Credits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31/2011 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	1,000	1,000
3	Preferred Stock Issued (204)	250-251		
4	Capital Stock Subscribed (202, 205)	252		
5	Stock Liability for Conversion (203, 206)	252		
6	Premium on Capital Stock (207)	252	117,703,952	117,703,952
7	Other Paid-In Capital (208-211)	253		0
8	Installments Received on Capital Stock (212)	252		
9	(Less) Discount on Capital Stock (213)	254		
10	(Less) Capital Stock Expense (214)	254		0
11	Retained Earnings (215, 215.1, 216)	118-119	48,284,212	51,007,810
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119		0
13	(Less) Reacquired Capital Stock (217)	250-251		
14	Accumulated Other Comprehensive Income (Loss) (219)	117		-
15	TOTAL Proprietary Capital (Enter Total of lines 2 thru 14)		**165,989,164**	**168,712,762**
16	**LONG-TERM DEBT**			
17	Bonds (221)	256-257		
18	(Less) Reacquired Bonds (222)	256-257		
19	Advances from Associated Companies (223)	256-257		
20	Other Long-Term Debt (224)	256-257	115,090,000	139,469,000
21	Unamortized Premium on Long-Term Debt (225)	258-259		
22	(Less) Unamortized Discount on Long-Term Debt-Dr. (226)	258-259		
23	(Less) Current Portion of Long-Term Debt			-
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)		**115,090,000**	**139,469,000**
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases - Noncurrent (227)			
27	Accumulated Provision for Property Insurance (228.1)			
28	Accumulated Provision for Injuries and Damages (228.2)		14,389,869	6,866,075
29	Accumulated Provision for Pensions and Benefits (228.3)		11,878,086	13,115,715
30	Accumulated Miscellaneous Operating Provisions (228.4)		17,960	1,323,934
31	Accumulated Provision for Rate Refunds (229)			

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

COMPARATIVE BALANCE SHEET (Liabilities and Other Credits) (continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Year Balance (c)	Prior Year End Balance 12/31/2011 (d)
32	Long-Term Portion of Derivative Instrument Liabilities			
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges			
34	Asset Retirement Obligations (230)		547,358	492,967
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		**26,833,273**	**21,798,691**
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-Term Debt	256-257	24,000,000	22,000,000
38	Notes Payable (231)		2,000,000	
39	Accounts Payable (232)		23,561,296	29,061,081
40	Notes Payable to Associated Companies (233)			
41	Accounts Payable to Associated Companies (234)		1,646,553	1,739,028
42	Customer Deposits (235)		2,065,287	1,920,787
43	Taxes Accrued (236)	262-263	7,581,014	9,596,659
44	Interest Accrued (237)		2,370,713	2,818,204
45	Dividends Declared (238)			3,890,000
46	Matured Long-Term Debt (239)			
47	Matured Interest (240)			
48	Tax Collections Payable (241)		(177)	
49	Miscellaneous Current and Accrued Liabilities (242)	268	6,609,634	7,255,037
50	Obligations Under Capital Leases-Current (243)			
51	Derivative Instrument Liabilities (244)			436,636
52	(Less) Long-Term Portion of Derivative Instrument Liabilities			
53	Derivative Instrument Liabilities - Hedges (245)			
54	(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges			
55	TOTAL Current and Accrued Liabilities (Total of lines 37 thru 54)		**69,834,320**	**78,717,432**
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)		4,620,155	6,234,082
58	Accumulated Deferred Investment Tax Credits (255)		546,530	564,798
59	Deferred Gains from Disposition of Utility Plant (256)			
60	Other Deferred Credits (253)	269	50,631,548	52,872,667
61	Other Regulatory Liabilities (254)	278	4,230,506	3,412,345
62	Unamortized Gain on Reacquired Debt (257)	260		
63	Accumulated Deferred Income Taxes - Accelerated Amortization (281)			0
64	Accumulated Deferred Income Taxes - Other Property (282)		77,797,048	70,046,020
65	Accumulated Deferred Income Taxes - Other (283)		31,976,752	27,479,313
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		169,802,539	160,609,225
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		**547,549,296**	**569,307,111**

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

STATEMENT OF INCOME

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly, if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting mehods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	Reference Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
1	**UTILITY OPERATING INCOME**					
2	Gas Operating Revenues (400)	300-301	276,988,483	322,598,896		
3	Operating Expenses					
4	Operation Expenses (401)	317-325	193,328,100	229,870,595		
5	Maintenance Expenses (402)	317-325	5,114,841	4,192,321		
6	Depreciation Expense (403)	336-338	18,451,177	18,917,506		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-338	-	-		
8	Amortization and Depletion of Utility Plant (404-405)	336-338	923,958	707,464		
9	Amortization of Utility Plant Acq. Adj. (406)	336-338	-	-		
10	Amort. of Prop. Losses, Unrecovered Plant and Reg. Study Costs (407.1)		-	-		
11	Amortization of Conversion Expenses (407.2)		-	-		
12	Regulatory Debits (407.3)		368,759	(305,000)		
13	(Less) Regulatory Credits (407.4)		-	-		
14	Taxes Other Than Income Taxes (408.1)	262-263	26,801,066	29,581,713		
15	Income Taxes-Federal (409.1)	262-263	(1,253,216)	1,966,129		
16	Income Taxes-Other (409.1)	262-263	(87,115)	(45,800)		
17	Provision of Deferred Income Taxes (410.1)	234-235	8,815,956	6,967,131		
18	(Less) Provision for Deferred Income Taxes-Credit (411.1)	234-235	-	-		
19	Investment Tax Credit Adjustment - Net (411.4)		(18,268)	(76,982)		
20	(Less) Gains from Disposition of Utility Plant (411.6)		-	-		
21	Losses from Disposition of Utility Plant (411.7)		-	-		
22	(Less) Gains from Disposition of Allowances (411.8)		-	-		
23	Losses from Disposition of Allowances (411.9)		-	-		
24	Accretion Expense (411.10)		-	-		
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)		252,445,258	291,775,077		
26	Net Utility Operating Income (Total of lines 2 less 25) (Carry forward to page 116, line 27)		24,543,225	30,823,819		

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

STATEMENT OF INCOME

Line No.	Elec. Utility Current Year to Date (in dollars) (g)	Elec. Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1						
2	-	-	276,988,483	322,598,896	-	-
3						
4	-	-	193,328,100	229,870,595	-	-
5	-	-	5,114,841	4,192,321	-	-
6	-	-	18,451,177	18,917,506	-	-
7						
8	-	-	923,958	707,464	-	-
9	-	-	-	-	-	-
10	-	-	-	-	-	-
11	-	-	-	-	-	-
12	-	-	368,759	(305,000)	-	-
13	-	-	-	-	-	-
14	-	-	26,801,066	29,581,713	-	-
15	-	-	(1,253,216)	1,966,129	-	-
16	-	-	(87,115)	(45,800)	-	-
17	-	-	8,815,956	6,967,131	-	-
18	-	-	-	-	-	-
19	-	-	(18,268)	(76,982)	-	-
20	-	-	-	-	-	-
21	-	-	-	-	-	-
22	-	-	-	-	-	-
23	-	-	-	-	-	-
24	-	-	-	-	-	-
25	-	-	252,445,258	291,775,077	-	-
26	-	-	24,543,225	30,823,819	-	-

Name of Respondent **Cascade Natural Gas Corporation**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report **Dec. 31, 2012**

STATEMENT OF INCOME (continued)

Line No.	Title of Account (a)	Reference Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
27	Net Utility Operating Income (Carried fwd. from page 114)		24,543,225	30,823,819		
28	**OTHER INCOME AND DEDUCTIONS**					
29	Other Income					
30	Nonutility Operating Income					
31	Rev. From Merchandising, Jobbing & Contract Work (415)		-	-		
32	(Less) Costs & Exp. of Merch., Job. & Contr. Work (416)		-	-		
33	Revenues From Nonutility Operations (417)		14,974	31,390		
34	(Less) Expenses of Nonutilty Operations (417.1)		-	-		
35	Nonoperating Rental Income (418)		-	-		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-	-		
37	Interest and Dividend Income (419)		254,357	771,577		
38	Allow. for Other Finds Used During Construction (419.1)		464,259	116,584		
39	Miscellaneous Nonoperating Income (421)		23,623	67,945		
40	Gain on Disposition of Property (421.1)		-	-		
41	TOTAL Other Income (Total of Lines 31 thru 40)		757,213	987,496		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		-	-		
44	Miscellaneous Amortization (425)		-	-		
45	Donations (426.1)	340	221,908	153,213		
46	Life Insurance (426.2)		-	-		
47	Penalties (426.3)		-	423,383		
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		109,581	79,344		
49	Other Deductions (426.5)		60	226,301		
50	TOTAL Other Income Deducions (Total of Lines 43 thru 49)	340	331,549	882,241		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	3,638	3,470		
53	Income Taxes-Federal (409.2)	262-263	2,586	(16,479)		
54	Income Taxes-Other (409.2)	262-263	180	25		
55	Provision for Deferred Inc. Taxes (410.2)	234-235	-	-		
56	(Less) Provision for Deferred Income Taxes-Cr.(411.2)	234-235	-	-		
57	Investment Tax Credit Adjustments-Net (411.5)		-	-		
58	(Less) Investment Tax Credits (420)		-	-		
59	TOTAL Taxes on Other Income & Deductions (Total of 52-58)		6,404	(12,984)		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		419,260	118,239		
61	**INTEREST CHARGES**					
62	Interest on Long-Term Debt (427)		10,155,023	10,703,925		
63	Amortization of Debt Disc. and Expense (428)	258-259	120,628	123,854		
64	Amortization of Loss on Reacquired Debt (428.1)		249,054	268,788		
65	(Less) Amorttization of Premium on Debt-Credit (429)	258-259	-	-		
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)		-	-		
67	Interest on Debt to Associated Companies (430)	340	-	-		
68	Other Interest Expense (431)	340	1,342,152	872,004		
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit(432)		(288,422)	(68,732)		
70	Net Interest Charges (Total of lines 62 thru 69)		11,578,435	11,899,839		
71	Income Before Extraordinary Items (Total of lines 27, 60, and 70)		13,384,050	19,042,219		
72	**EXTRAORDINARY ITEMS**					
73	Extraordinary Income (434)		-	-		
74	(Less) Extraordinary Deductions (435)		-	-		
75	Net Extraord. Items (Enter Total of line 73 less line 74)		-	-		
76	Income Taxes - Federal and Other (409.3)	262-263	-	-		
77	Extraord. Items After Taxes (Total of line 75 less line 76)		-	-		
78	Net Income (Total of lines 71 and 77)		13,384,050	19,042,219		

Name of Respondent **Cascade Natural Gas Corporation**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report **Dec. 31, 2012**

STATEMENT OF INCOME (continued)

Line No.	Elec. Utility Current Year to Date (in dollars) (g)	Elec. Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
27	-	-	24,543,225	30,823,819	-	-
28	[redacted]					
29						
30						
31	-	-	-	-	-	-
32	-	-	-	-	-	-
33	-	-	14,974	31,390	-	-
34	-	-	-	-	-	-
35	-	-	-	-	-	-
36	-	-	-	-	-	-
37	-	-	254,357	771,577	-	-
38	-	-	464,259	116,584	-	-
39	-	-	23,623	67,945	-	-
40	-	-	-	-	-	-
41	-	-	757,213	987,496	-	-
42	[redacted]					
43			-	-		
44			-	-		
45			221,908	153,213		
46			-	-		
47			-	423,383		
48			109,581	79,344		
49	-	-	60	226,301	-	-
50	-	-	331,549	882,241	-	-
51	[redacted]					
52			3,638	3,470		
53	-	-	2,586	(16,479)	-	-
54	-	-	180	25	-	-
55	-	-	-	-	-	-
56	-	-	-	-	-	-
57	-	-	-	-	-	-
58	-	-		-	-	-
59	-	-	6,404	(12,984)	-	-
60	-	-	419,260	118,239	-	-
61	[redacted]					
62	-	-	10,155,023	10,703,925	-	-
63	-	-	120,628	123,854	-	-
64	-	-	249,054	268,788	-	-
65	-	-	-	-	-	-
66	-	-	-	-	-	-
67	-	-	-	-	-	-
68	-	-	1,342,152	872,004	-	-
69	-	-	(288,422)	(68,732)	-	-
70	-	-	11,578,435	11,899,839	-	-
71	-	-	13,384,050	19,042,219	-	-
72	[redacted]					
73	-	-	-	-	-	-
74	-	-	-	-	-	-
75	-	-	-	-	-	-
76	-	-	-	-	-	-
77	-	-	-	-	-	-
78	-	-	13,384,050	19,042,219	-	-

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec. 31, 2012**

Statement of Accumulated Comprehensive Income and Hedging Activities

1. Report in columns (b), (c) and (e) the amounts of accumlated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

Line No.	Item (a)	Unrealized Gains and Losses on availabl-for-sale securities (b)	Minimum Pension liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		-		
2	Preceding Quarter/Year to Date Reclassification from Account 219 to Net Income		-		
3	Preceding Quarter/Year to Date Changes in Fair Value		-		
4	Total (lines 2 and 3)		-		
5	Balance of Account 219 at End of Preceding Quarter/Year		-		
6	Balance of Account 219 at Beginning of Current Year		-		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income		-		
8	Current Quarter/Year to Date Changes in Fair Value		-		
9	Total (lines 7 and 8)		-		
10	Balance of Account 219 at End of Current Year		-		

Statement of Accumulated Comprehensive Income and Hedging Activities (continued)

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges (Insert Category) (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1	0		-		
2	0		-		
3	0		-		
4	0		-	19,042,219	19,042,219
5	0		-		
6	0		-		
7	0		-		
8	0		-		
9	0		-	13,384,050	13,384,050
10	0		-		

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

Statement of Retained Earnings

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436-439 inclusive). Show the contra primary account affected in column (b).
3. State the purpose and amount for each reservation or appropriation of retained earnings.
4. List first Account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items, in that order.
5. Show dividends for each class and series of capital stock.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Year Year to Date Balance (c)	Previous Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS			
1	Balance - Beginning of Period		51,007,810	47,028,199
2	Changes (Identify by prescribed retained earnings accounts)			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6	Balance Transferred from Income		13,384,050	19,042,219
7	Appropriations of Retained Earnings (Account 436)			
8				
9	Dividends Declared-Preferred Stock (Account 437)			
10				
11	Dividends Declared-Common Stock (Account 438)			
12			(16,107,648)	(15,062,608)
13	Transfers from Account 216.1, Unappropriated Undistributed Subsidiary Earnings			
14	Balance-End of Period (Total of lines 1, 4, 5, 6, 8, 10, 12, and 13)		48,284,212	51,007,810
15	APPROPRIATED RETAINED EARNINGS (Account 215)			
16	TOTAL Appropriated Retained Earnings (Account 215) (footnote details)			
17	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE, FEDERAL (Account)			
18	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal (Account			
19	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1) (Total of lines			
20	TOTAL Retained Earnings (Accounts 215, 215.1, 216) (Total of lines 14 and 1		48,284,212	51,007,810
21	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)			
	Report only on an Annual Basis no Quarterly			
22	Balance-Beginning of Year (Debit or Credit)			
23	Equity in Earnings for Year (Credit) (Account 418.1)			
24	(Less) Dividends Received (Debit)			
25	Other Changes (Explain)			
26	Balance-End of Year			

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Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identif separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliatic between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Shee
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financir activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and incom taxes paid.
(4) Investing Activities: Include at Other (line 25) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilitie assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA Gener Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cos

Line No.	Description (See instructions for explanation of codes) (a)	Current Year To Date Quarter/Year	Previous Year To Date Quarter/Year
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78 (c) on page 116)	13,384,050	19,042,219
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	19,375,135	19,624,970
5	Amortization of (specify)		
5.01	Debt issuance costs	-	-
5.02	Gas cost changes	(394,385)	6,014,585
6	Deferred Income Taxes (Net)	8,815,956	6,585,149
7	Investment Tax Credit Adjustments (Net)	(18,268)	4,510,279
8	Net (Increase) Decrease in Receivables	12,220,023	
9	Net (Increase) Decrease in Inventory	3,663,866	
10	Net (Increase) Decrease in Allowance Inventory		
11	Net Increase (Decrease) in Payables and Accrued Expenses	(9,180,175)	
12	Net (Increase) Decrease in Other Regulatory Assets		
13	Net Increase (Decrease) in Other Regulatory Liabilities		
14	(Less) Allowance for Other Funds Used During Construction		
15	(Less) Undistributed Earnings From Subsidary Companies		
16	Other:		
16.01	Net change in other deferred balances	(2,414,524)	(286,240)
16.02			
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of Lines 2 thru 16)	45,451,678	55,490,962
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross additions to Utility Plant (less nuclear fuel)	(38,577,286)	(26,127,609)
23	Gross additions to Nuclear Fuel		
24	Gross additions to common Utility Plant		
25	Gross additions to Nonutility Plant		
26	(Less) Allowance for Other Funds Used During Construction	(464,259)	(116,584)
27	Other:		
27.01	Net increase in customer advances for construction	(1,613,927)	(751,280)
27.02			
28	Cash Outflows for Plant (Total of Lines 22 thru 27.01)	(40,655,472)	(26,995,473)
29			
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)	7,222,164	
32			
33	Investments in and advances to associated & subsidiary companies	-	-
34	Contributions and advances from associated & subsidiary companies	-	-
35	Disposition of Investments in (and advances to)		
36	associated and subsidiary companies	-	-
37			
38	Purchase of Investment Securities (a)	-	-
39	Proceeds from Sales of Investment Securities (a)	-	-

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

STATEMENT OF CASH FLOWS (continued)

Line No.	Description (See instructions for explanation of codes) (a)	Current Year To Date Quarter/Year	Previous Year To Date Quarter/Year
40	Loans made or purchased	-	-
41	Collections on loans		
42			
43	Net (Increase) Decrease in Receivables		80,890
44	Net (Increase) Decrease in Inventory		
45	Net (Increase) Decrease in Allowances Held for Speculation		
46	Net Increase (Decrease) in Payables and Accrued Expenses		
47	Other: SERP Assets	(260,669)	549,293
47.01			
47.02			
48	Net Cash Provided by (Used In) Investing Activities		
49	(Total of Lines 28 thru 47)	(33,693,977)	(26,365,290)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)	-	-
54	Preferred Stock		
55	Common Stock	-	-
56		-	-
56.01			
57	Net Increase in Short-Term Debt (c)	2,000,000	-
58			
58.01			
58.02			
59	Cash Provided by Outside Sources (Total of Lines 53 thru 58	2,000,000	-
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)	(22,379,000)	(720,000)
63	Preferred Stock		
64	Common Stock		
65			
65.01			
66	Net Decrease in Short-Term Debt (c)		
67			
68	Dividends on Preferred Stock		
69	Dividends on Common Stock	(19,990,000)	(14,810,000)
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of Lines 59 thru 69)	(40,369,000)	(15,530,000)
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of Lines 18, 49, and 71)	(28,611,299)	13,595,672
75			
76	Cash and Cash Equivalents at Beginning of Period	29,032,933	15,437,261
77			
78	Cash and Cash Equivalents at End of Period	421,634	29,032,933

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

NOTES TO FINANCIAL STATEMENTS

1. Provide important disclosures regarding the Balance Sheet, Statement of Income for the Year, Statement of Retained Earnings for the Year, and Statement of Cash Flow, or any account thereof. Classify the disclosures according to each financial statement, providing a subheading for each statement except where a disclosure is applicable to more than one statement. The disclosures must be on the same subject matters and in the same level of detail that would be required if the respondent issued general purpose financial statements to the public or shareholders.
2. Furnish details as to any significant contingent assets or liabilities existing at year end, and briefly explain any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or a claim for refund of income taxes of a material amount initiated by the utility. Also, briefly explain any dividends in arrears on cumulative preferred stock.
3. Furnish details on the respondent's pension plans, post-retirement benefits other than pensions (PBOP) plans, and post-employment benefit plans as required by instruction no. 1 and, in addition, disclose for each individual plan the current year's cash contributions. Furnish details on the accounting for the plans and any changes in the method of accounting for them. Include details on the accounting for transition obligations or assets, gains or losses, the amounts deferred and the expected recovery periods. Also, disclose any current year's plan or trust curtailments, terminations, transfers, or revisions of assets. Entities that participate in multiemployer postretirement plans e.g. parent company sponsored pensin plans) disclose in addition to the required disclosures for the consolidated plan, (1) the amount of cost recognized in the respondent's financial statements for each plan for the period presented, and (2) the basis for determining the respondent's share of the total plan costs.
4. Furnish details on the respondent's asset retirement obligations (ARO) as required by instruction no. 1 and, in addition, disclose the amounts recovered through rates to settle such obligations. Identify any mechanism or account in shich recovered funds are being placed (i.e. trust funds, insurance policies, surety bonds). Furnish details on the accounting for the asset retirement obligations and any changes in the measurement or method of accounting for the obligations. Include details on the accounting for the settlement of the obligations and any gains or losses expected or incurred on the settlement.
5. Provide a list of all environmental credits received during the reporting period.
6. Provide a summary of revenues and expenses for each tracked cost and special surcharge.
7. Where account 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
8. Explain concisely any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
9. Disclose details on any significant financial changes during the reporting year to the respondent or the respondent's consolidated group that directly affect the respondent's gas pipeline operations, including: sales, transfers or mergers of affiliates, investments in new partnerships, sales of gas pipeline facilities or the sale of ownership interests in the gas pipeline to limited partnerships, investments in related industries (i.e., production, gathering), major pipeline investments, acquisitions by the parent corporation(s), and distributions of capital.
10. Explain concisely unsettled rate proceedings where a contingency exists such that the company may need to refund a material amount to the utility's customers or that the utility may receive a material refund with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects and explain the major factors that affect the rights of the utility to retain such revenues or to recover amounts paid with respect to power and gas purchases.
11. Explain concisely significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and summarize the adjustments made to balance sheet, income, and expense accounts.
12. Explain concisely only those significant changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.
13. For the 3Q disclosures, respondent must provide in the notes suffiecient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
14. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material affect on the respondent. Respondent must include in thenotes significnat changes since the most recently completed year in such items as: accounting priciples and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowing or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
15. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instuctions, such notes may be included herein.

The accompanying notes relate to MDU Energy Capital, LLC and its subsidiary companies, while the financial statements in this FORM 2 Report reflect only the unconsolidated statements of Cascade Natural Gas Corporation. Cascade's subsidiary companies were dissolved as of 12/31/08 and do not have a material effect on the Notes to the Financial Statements.

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2012 and 2011

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation

The Company is incorporated under the laws of the state of Delaware and is a direct wholly owned subsidiary of MDU. The Company is parent to PCEH, and its wholly owned subsidiary Cascade, and PIEH, and its wholly owned subsidiary Intermountain.

Cascade and Intermountain's natural gas distribution operations sell natural gas at retail and provide natural gas transportation services to certain customers on their systems. The Cascade service territory consists of towns in western, southeastern and south-central Washington and central and eastern Oregon. The Intermountain service territory is located solely in southern Idaho, encompassing communities located across the Snake River Plain. Cascade is subject to regulation by the WUTC and the OPUC. Intermountain is subject to regulation by the IPUC. These markets tend to be seasonal and sales to residential and commercial customers are influenced by fluctuations in temperature, particularly during the winter season. Consumption is also influenced by the energy efficiency of customers' appliances, as well as consumer decisions to reduce natural gas usage in response to higher prices. Cascade filed an application for a decoupling mechanism with the OPUC. The OPUC approved an extension until April 30, 2013, of Cascade's existing decoupling mechanism, which was scheduled to expire in the third quarter of 2012. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

The consolidated financial statements and disclosures of the Company are presented in accordance with GAAP. The accounting policies followed by Cascade and Intermountain are generally subject to the FERC.

Cascade and Intermountain account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the applicable state public utility commissions. See Note 3 for more information regarding the nature and amounts of these regulatory deferrals.

Depreciation and amortization expense is reported separately on the Consolidated Statements of Income and, therefore, is excluded from the other line items within the operations expenses.

Management has also evaluated the impact of events occurring after December 31, 2012, up to the date of the issuance of these consolidated financial statements on March 28, 2013.

Cash and cash equivalents

The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts. The total balance of receivables past due 90 days or more was $1.1 million and $3.1 million as of December 31, 2012 and 2011, respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of December 31, 2012 and 2011, was $926,000 and $1.0 million, respectively.

Inventories and natural gas in storage

Inventories, other than natural gas in storage, consisted of materials and supplies of $8.1 million and $7.9 million as of December 31, 2012 and 2011, respectively. These inventories were stated at the lower of average cost or market value. Natural gas in storage is carried at cost using the first-in, first-out method at Cascade and using the average-cost method at Intermountain. Natural gas in storage is expected to be used within one year and the value included in inventories was $7.9 million and $11.8 million at December 31, 2012 and 2011, respectively.

Investments

The Company's investments include the cash surrender value of life insurance policies and an insurance investment contract. The Company has elected to measure its investment in the insurance investment contract at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. For more information, see Notes 5 and 9.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. The amount of AFUDC capitalized was $1.9 million for the year ended December 31, 2012 and $523,000 for the year ended December 31, 2011. Property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets. The Company collects removal costs for plant assets in regulated utility rates and records them as a regulatory liability.

Property, plant and equipment at December 31 were as follows:

	2012	2011	Weighted Average Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Distribution plant	**$ 1,007,868**	$ 972,895	40
Transmission plant	**85,861**	63,522	52
Storage plant	**16,512**	16,525	38
General plant	**116,651**	106,833	14
Other plant	**25,773**	18,726	14
Non-depreciable plant	**6,093**	5,800	N/A
Less: Accumulated depreciation and amortization	**469,804**	441,162	
Net property, plant and equipment	**$ 788,954**	$ 743,139	

Impairment of long-lived assets
The Company reviews the carrying values of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No impairment losses were recorded in 2012 and 2011. Unforeseen events and changes in circumstances could require the recognition of other impairment losses at some future date.

Goodwill
Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired. MDU and the Company perform the annual review for goodwill impairment at the reporting unit level, which MDU has determined to be the operating segment. This review is also performed at the Company level as separate financial statements are prepared.

The goodwill impairment test is a two-step process. The first step of the impairment test involves comparing the fair value of the reporting unit to its carrying value. If the fair value of the reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of the reporting unit is less than its carrying value, step two of the test is performed to determine the amount of the impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2012 and 2011, there were no impairment losses recorded. At December 31, 2012, the fair value exceeded the carrying value for the Company level on a separate basis. For more information on goodwill, see Note 2.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital. The weighted average cost of capital of approximately 6 percent, and a long-term growth rate projection of approximately 3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2012. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies. These multiples are applied to operating data to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Cascade and Intermountain was $46.5 million and $48.4 million at December 31, 2012 and 2011, respectively. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenue net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price and interest rate risk management program to efficiently manage and minimize commodity price and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions, and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties.

The Company's policy requires that interest rate derivative instruments not exceed a period of 24 months. The Company’s policy allows the hedging of monthly forecasted purchases of natural gas at Cascade and Intermountain for a period up to three years.

The Company's policy also requires settlement of natural gas derivative instruments at Cascade and Intermountain monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days. The Company has policies and procedures that management believes minimize credit-risk exposure. Accordingly, the Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 4.

The Company's derivative instruments are reflected at fair value. For more information see Note 5.

Asset retirement obligations

The Company performed detailed assessments of ARO’s for the removal of natural gas transmission, distribution, and storage facilities. The Company records the fair value of a liability for an ARO in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a regulatory asset or liability. Certain ARO’s have been identified, however, based on the indeterminate life of those assets, an ARO calculation cannot be made, and accordingly, an ARO has not been recorded for those items. For more information on asset retirement obligations, see Note 7.

Legal costs

The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public utility commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $35.3 million and $45.1 million at December 31, 2012 and 2011, respectively.

Insurance

Cascade and Intermountain are insured for workers' compensation losses in guaranteed cost programs. Automobile liability and general liability losses are insured, subject to self insured retentions of $500,000 per accident or occurrence. The companies also have coverage above the self insured retentions on a claims first-made and reported basis beyond the retained levels. Cascade and Intermountain are retaining losses up to their respective retentions accrued on the basis of estimates of liability for claims incurred and estimates of liability for claims incurred but not reported.

Income taxes

MDU and its subsidiaries file consolidated federal income tax returns and combined and separate state income tax returns. Federal income taxes paid by MDU, as parent of the consolidated group, are allocated to the individual subsidiaries based on the ratio of the separate company computations of tax. MDU makes a similar allocation for state income taxes paid in connection with combined state filings. The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Regulated entities are required to recognize such adjustment to deferred income taxes as regulatory assets or liabilities if it is probable that such amounts will be recovered from or refunded to customers in future rates. Taxes recoverable from customers have been recorded as a regulatory asset and are included in deferred charges and other assets. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other regulatory liabilities-noncurrent. These regulatory assets and liabilities are expected to be recovered from or refunded to customers in future rates in accordance with applicable regulatory procedures.

Consistent with orders and directives of the IPUC, Intermountain does not provide state deferred income tax expense for certain income tax temporary differences and instead recognized the tax impact currently (commonly referred to as flow-through accounting) for rate making and financial reporting. Therefore, the Company’s effective income tax rate is impacted as these differences arise and reverse.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public utility commissions.

Tax positions taken or expected to be taken in an income tax return are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

Use of estimates

The preparation of financial statements in conformity with GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of long-lived assets and goodwill; fair values of acquired assets and liabilities under the acquisition method of accounting; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; and the fair value of derivative instruments. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information

Cash expenditures for interest and income taxes for the years ended December 31 were as follows:

	2012	2011
	(In thousands)	
Interest, net of amount capitalized	**$ 22,701**	$ 23,422
Income taxes refunded, net	**$ (3,196)**	$ (3,670)

Noncash investing transactions at December 31 were as follows:

	2012	2011
	(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 11,949**	$ 2,016

New accounting standards

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements. The guidance generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the guidance includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This guidance was effective for the Company on January 1, 2012. The guidance required additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Disclosures about an Employer's Participation in a Multiemployer Plan In September 2011, the FASB issued guidance on an employer's participation in multiemployer benefit plans. The guidance was issued to enhance the transparency of disclosures about the significant multiemployer plans in which employers participate, the level of the employer's participation in those plans, the financial health of the plans and the nature of the employer's commitments to the plans. This guidance is effective for the Company on December 31, 2012, and must be applied retrospectively. The guidance required additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Disclosures about Offsetting Assets and Liabilities In December 2011, the FASB issued guidance on the disclosure requirements related to balance sheet offsetting. The new disclosure requirements relate to the nature of an entity's rights of offset and related arrangements associated with its financial instruments and derivative instruments. The guidance is effective for the Company on January 1, 2013 and must be applied retrospectively. The Company is evaluating the effects of this guidance on disclosures, but it will not impact the Company's results of operations, financial position or cash flows.

NOTE 2 – GOODWILL

The carrying amount of goodwill for the years ended December 31, 2012 and 2011 remained unchanged at $340,924. No impairments have been recorded in any periods.

NOTE 3 – REGULATORY ASSETS AND LIABILITIES

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	Estimated Recovery Period *	**2012**	2011
		(In thousands)	
Regulatory assets:			
Deferred income taxes	**	**$ 72,951**	$ 73,356
Pension and postretirement benefits (a)	(e)	**61,825**	62,434
Taxes recoverable from customers (a)	---	**9,078**	12,433
Natural gas supply derivatives (b)	---	**---**	437
Manufactured gas plant remediation (a)	Determined upon filing	**15,374**	7,605
Washington gas management margin sharing (a)	1 year	**179**	218
Long-term debt refinancing costs (a)	Up to 25 years	**1,017**	1,266
Conservation activities (a)	1 year	**3,935**	4,402
Other (a)	Up to 50 years	**584**	749
Total regulatory assets		**164,943**	162,900
Regulatory liabilities:			
Plant removal costs (c)		**177,655**	177,639
Natural gas costs refundable through rate adjustments		**35,262**	45,064
Deferred income taxes**		**32,125**	30,301
Taxes refundable to customers (c)		**11,769**	17,532
Northwest Pipeline Settlement Agreement (d)		**---**	1,483
Other (c)		**5,848**	5,445
Total regulatory liabilities		**262,659**	277,464
Net regulatory position		**$ (97,716)**	$ (114,564)

* *Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.*
*** Represents deferred income taxes related to regulatory assets and liabilities. The deferred income tax assets are not earning a rate of return.*
(a) Included in deferred charges and other assets on the Consolidated Balance Sheets.
(b) Included in prepayments and other current assets on the Consolidated Balance Sheets.
(c) Included in other regulatory liabilities - noncurrent on the Consolidated Balance Sheets.
(d) Included in other accrued liabilities on the Consolidated Balance Sheets.
(e) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from

customers in future rates. Excluding deferred income taxes, as of December 31, 2012 and 2011, approximately $91.5 million and $85.3 million, respectively, of regulatory assets were not earning a rate of return.
If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of regulatory accounting occurs.

NOTE 4 – DERIVATIVE INSTRUMENTS
Derivative instruments, including certain derivative instruments embedded in other contracts, are required to be recorded on the balance sheet as either an asset or liability measured at fair value. The Company's policy is to not offset fair value amounts for derivative instruments, and as a result the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. Changes in the derivative instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would be discontinued and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity.

The Company evaluates counterparty credit risk on its derivative assets and the Company's credit risk on its derivative liabilities. As of December 31, 2012 and 2011, credit risk was not material.

Cascade
Cascade has historically utilized natural gas swap agreements to manage a portion of their regulated natural gas supply portfolio in order to manage fluctuations in the price of natural gas related to core customers in accordance with authority granted by the WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. As of December 31, 2012, Cascade had no outstanding swap agreements. The fair value of derivative instruments must be estimated as of the end of each reporting period and recorded on the Consolidated Balance Sheets as an asset or a liability. Periodic changes in the fair market value of derivative instruments are recorded on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Gains and losses on the settlements of derivative instruments are recorded as a component of purchased natural gas sold on the Consolidated Statements of Income as they are recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade either pays or

receives settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract. For the years ended December 31, 2012 and 2011, the change in the fair market value of the derivative instruments of $437,000 and $8.9 million, respectively, were recorded as a decrease to regulatory assets.

The location and fair value of the Company's derivative instruments on the Consolidated Balance Sheets were as follows:

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2012	Fair Value at December 31, 2011
		(In thousands)	
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	**$ ---**	$ 437
Total liability derivatives		**$ ---**	$ 437

NOTE 5 – FAIR VALUE MEASUREMENTS

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance investment contract, to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $2.3 million and $1.8 million as of December 31, 2012 and 2011, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gain on these investments for the year ended December 31, 2012, was $240,000. The net unrealized loss on these investments for the year ended December 31, 2011, was $54,000. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The fair value of the Company's money market funds approximates cost.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs.

The estimated fair values of the Company's assets and liabilities measured on a recurring basis are determined using the market approach.

The Company's Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer.

The estimated fair value of the Company's Level 2 insurance investment contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

The estimated fair value of the Company's Level 2 commodity derivative instruments is based upon futures prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company’s and the counterparty’s nonperformance risk is also evaluated.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2012 and 2011, there were no transfers between Levels 1 and 2.

The Company’s assets and liabilities measured at fair value on a recurring basis are as follows:

	Fair Value Measurements at December 31, 2012, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2012
		(In thousands)		
Assets:				
Money market funds	$ ---	$ 1,118	$ ---	$ 1,118
Available-for-sale securities:				
Insurance investment contract*	---	2,264	---	2,264
Total assets measured at fair value	$ ---	$ 3,382	$ ---	$ 3,382

** The insurance investment contract invests approximately 28 percent in common stock of mid-cap companies, 28 percent in common stock of small-cap companies, 29 percent in common stock of large-cap companies and 15 percent in fixed-income and other investments.*

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
		(In thousands)		
Assets:				
Available-for-sale securities:				
Insurance investment contract*	$ ---	$ 1,777	$ ---	$ 1,777
Total assets measured at fair value	$ ---	$ 1,777	$ ---	$ 1,777
Liabilities:				
Commodity derivative instruments - current	$ ---	$ 437	$ ---	$ 437
Total liabilities measured at fair value	$ ---	$ 437	$ ---	$ 437

** The insurance investment contract invests approximately 33 percent in common stock of mid-cap companies, 34 percent in common stock of small-cap companies, 32 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.*

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only. The fair value was based on discounted future cash flows using current market interest rates. The estimated fair value of the Company's Level 2 long-term debt at December 31 was as follows:

	2012		2011	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$ 335,727**	**$ 381,122**	$ 371,478	$ 423,068

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities approximate their fair values.

NOTE 6 – DEBT

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2012. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

The following table summarizes the outstanding credit facilities of the Company and its subsidiaries:

Company	Facility	Facility Limit	Amount Outstanding at December 31, 2012	Amount Outstanding at December 31, 2011	Letters of Credit at December 31, 2012	Expiration Date
			(Dollars in millions)			
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (a)	$ 2.0	$ ----	$ ----	12/27/13
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (b)	$ 26.2	$ 8.1	$ ----	08/11/13

(a) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(b) Certain provisions allow for increased borrowings, up to a maximum of $80 million.

The following includes information related to the preceding table.

Short-term borrowings

Cascade Natural Gas Corporation The weighted average interest rate for borrowings outstanding at December 31, 2012, was 3.3 percent.

Cascade's credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, Cascade will be in default under the credit agreement. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness. Management expects to be able to refinance the revolving credit agreement on a long-term basis in 2013.

Intermountain Gas Company The weighted average interest rate for borrowings outstanding at December 31, 2012, was 2.3 percent. These borrowings were classified as short-term borrowings because the revolving credit agreement expires within one year. The borrowings outstanding as of December 31, 2011, were classified as long-term debt as they were intended to be refinanced on a long-term basis through continued borrowings. Management expects to be able to refinance the revolving credit agreement on a long-term basis in 2013.

The credit agreement contains customary covenants and provisions, including covenants of Intermountain not to permit, as of the end of any fiscal quarter, the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

Intermountain's credit agreement contains cross-default provisions. These provisions state that if (A) Intermountain fails to make any payment with respect to any indebtedness or guarantee in excess of a specified amount, (B) any other event occurs that would permit the holders of indebtedness or the beneficiaries of guarantees to become payable, or (C) certain conditions result in an early termination date under any swap contract that is in excess of $10 million, then Intermountain shall be in default under the revolving credit agreement.

Long-term debt

MDU Energy Capital, LLC The ability to request additional borrowings under the master shelf agreement expired; however, there is debt outstanding that is reflected in the following table. The master shelf agreement contains customary covenants and provisions, including covenants of the Company not to permit (A) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (B) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent, or (C) the ratio of Intermountain’s total debt (determined on a consolidated basis) to total capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of the Company’s earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter, to be greater than 1.5 to 1. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement).

The Company entered into a note purchase agreement on October 22, 2012, and issued $25.0 million of Senior Notes with due dates ranging from October 2022 to October 2042 at a weighted average interest rate of 4.1 percent. The Company contracted to issue an additional $25.0 million of Senior Notes under the agreement on May 15, 2013. The note purchase agreement contains customary covenants and provisions which are no more restrictive than the covenants described above for the master shelf agreement.

Long-term Debt Outstanding Long-term debt outstanding at December 31 was as follows:

	2012	2011
	(In thousands)	
Senior Notes at a weighted average rate of 5.72%, due on dates ranging from October 1, 2013 to May 15, 2043	**$ 236,637**	$ 241,909
Medium-Term Notes, at a weighted average rate of 7.58% due on dates ranging from February 4, 2013 to March 16, 2029	**59,000**	81,000
Credit agreement	**---**	8,100
Other notes, at a weighted average rate of 5.24% due on dates ranging from September 1, 2020 to February 1, 2035	**40,090**	40,469
Total long-term debt	**$ 335,727**	$ 371,478
Less current maturities	**59,273**	52,273
Net long-term debt	**$ 276,454**	$ 319,205

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2012, aggregate $59.3 million in 2013; $5.3 million in 2014; $55.3 million in 2015; $5.3 million in 2016; $40.3 million in 2017 and $170.2 million thereafter.

NOTE 7 – ASSET RETIREMENT OBLIGATIONS

The Company records asset retirement obligations related to certain natural gas distribution system assets.

A reconciliation of the Company's liability, which is included in other liabilities, for the years ended December 31 was as follows:

	2012	2011
	(In thousands)	
Balance at beginning of year	**$493**	$493
Accretion expense	**54**	---
Balance at end of year	**$547**	$493

The Company believes that any expenses related to asset retirement obligations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets.

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2012 and 2011

NOTE 8 – INCOME TAXES

Income before income taxes for the years ended December 31, 2012 and 2011 was $27,872 and $40,775, respectively.

Income tax expense for the periods ended December 31 was as follows:

	2012	2011
	(In thousands)	
Current:		
Federal	**$ (5,261)**	$ 635
State	**(264)**	644
	(5,525)	1,279
Deferred:		
Income taxes –		
Federal	**13,663**	12,234
State	**906**	165
Investment tax credit	**101**	166
	14,670	12,565
Change in uncertain tax benefits	---	(246)
Change in accrued interest	**37**	98
Total income tax expense	**$ 9,182**	$ 13,696

Components of deferred tax assets and deferred tax liabilities at December 31 were as follows:

	2012	2011
	(In thousands)	
Deferred tax assets:		
Regulatory matters	**$ 72,951**	$ 73,356
Contingency reserve	**5,315**	2,471
Accrued pension costs	**21,651**	16,222
Other	**3,483**	3,009
Total deferred tax assets	**103,400**	95,058
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**188,836**	165,317
Regulatory matters	**32,125**	30,301
Other	**144**	170
Total deferred tax liabilities	**221,105**	195,788
Net deferred income tax liability	**$ (117,705)**	$ (100,730)

As of December 31, 2012 and 2011, no valuation allowance has been recorded associated with the above deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2011, to December 31, 2012, to deferred income tax expense:

	2012
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 16,975**
Regulatory matters	**(2,305)**
Deferred income tax expense for the period	**$ 14,670**

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference were as follows:

Years ended December 31,	**2012**		2011	
	Amount	%	Amount	%
	(Dollars in thousands)			
Computed tax at federal statutory rate	**$ 9,756**	**35.0**	$ 14,272	35.0
Increases (reductions) resulting from:				
State income taxes, net of federal income tax benefit	**158**	**0.6**	570	1.4
Amortization and deferral of investment tax credit	**53**	**0.2**	(71)	(0.2)
Resolution of tax matters and uncertain tax positions	**31**	**0.1**	(598)	(1.5)
Flow-through	**(93)**	**(0.4)**	(335)	(0.8)
AFUDC	**(416)**	**(1.5)**	(41)	(0.1)
Other items	**(307)**	**(1.1)**	(101)	(0.2)
Total income tax expense	**$ 9,182**	**32.9**	$ 13,696	33.6

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction and various state jurisdictions. The Company is no longer subject to U.S. federal or state income tax examinations by tax authorities for years ending prior to 2007. The 2007 through 2009 tax years are currently under audit.

A reconciliation of the unrecognized tax benefits (excluding interest) for the years ended December 31 was as follows:

	2012	2011
	(In thousands)	
Balance at beginning of year	**$ 2,559**	$ 1,675
Additions for tax positions of prior years	---	1,130
Settlements	---	(246)
Balance at end of year	**$ 2,559**	$ 2,559

Included in the balance of unrecognized tax benefits at December 31, 2012 and 2011, were $1.1 million and $1.1 million, respectively, of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $1.7 million, including approximately $296,000 for the payment of interest and penalties at December 31, 2012, and was $1.6 million, including approximately $220,000 for the payment of interest and penalties at December 31, 2011.

It is likely that substantially all of the unrecognized tax benefits, as well as interest, at December 31, 2012, will be settled in the next twelve months due to the anticipated settlement of federal and state audits.

For the years ended December 31, 2012 and 2011, the Company recognized $45,000 and $188,000, respectively, in interest expense and no penalties related to unrecognized tax benefits. The Company recognized interest income of approximately $12,000 and $31,000 for the years ended December 31, 2012 and 2011, respectively. The Company had accrued liabilities of approximately $257,000 and $220,000 at December 31, 2012 and 2011, respectively, for the payment of interest.

NOTE 9 – EMPLOYEE BENEFIT PLANS

Pension and other postretirement benefit plans

The Company has a noncontributory defined benefit pension plan and other postretirement benefit plans for certain eligible employees. Effective October 1, 2003, Cascade amended the defined pension plan so that no new salaried participants will be added to the plan and no additional benefits will accrue for existing salaried participants. Effective January 1, 2007, the defined pension plan was amended so no new operational union employees would be added to the plan and eligible existing union participants would accrue a benefit at an annual rate of $107 per year. Effective September 30, 2012, Cascade's pension service accrual credit for union employees ceased. The Company's pension assets are included in MDU's master trust. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at Cascade and Intermountain. Current employees at Intermountain, and those hired before June 1, 1992 at Cascade, who attained age 55 with 10 years of continuous service by December 31, 2010, will be provided the current retiree medical insurance benefits or can elect the new benefit, if desired, regardless of when they retire. All other current employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire. These employees will be eligible for a specified company funded Retiree Reimbursement Account. Employees at Intermountain hired after December 31, 2009, and employees at Cascade hired after June 1, 1992, will not be eligible for retiree medical benefits.

In 2012, the Company modified health care coverage for certain retirees. Effective January 1, 2013, post-65 coverage is replaced by a fixed-dollar subsidy for retirees and spouses to be used to purchase individual insurance through an exchange.

Changes in benefit obligation and plan assets for the years ended December 31, 2012 and 2011, respectively and amounts recognized in the Consolidated Balance Sheets at December 31, 2012 and 2011, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	**2012**	2011
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 87,104**	$ 73,473	**$ 25,345**	$ 22,241
Service cost	**939**	1,075	**197**	151
Interest cost	**3,473**	3,752	**912**	1,103
Plan participants' contributions	**---**	---	**458**	503
Actuarial (gain) loss	**5,618**	12,668	**(1,250)**	2,991
Benefits paid	**(4,147)**	(3,864)	**(1,828)**	(1,644)
Benefit obligation at end of year	**92,987**	87,104	**23,834**	25,345
Change in net plan assets:				
Fair value of plan assets at beginning of year	**55,011**	52,565	**17,079**	18,201
Actual gain (loss) on plan assets	**6,901**	(934)	**1,660**	(209)
Employer contribution	**4,949**	7,244	**411**	228
Plan participants' contributions	**---**	---	**458**	503
Benefits paid	**(4,147)**	(3,864)	**(1,828)**	(1,644)
Fair value of net plan assets at end of year	**62,714**	55,011	**17,780**	17,079
Funded status - under	**$ (30,273)**	$ (32,093)	**$ (6,054)**	$ (8,266)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other liabilities (noncurrent)	**$ (30,273)**	$ (32,093)	**$ (6,054)**	$ (8,266)
Net amount recognized	**$ (30,273)**	$ (32,093)	**$ (6,054)**	$ (8,266)
Amounts recognized in regulatory assets (liabilities) consist of:				
Actuarial loss	**$ 45,408**	$ 45,014	**$ 12,340**	$ 15,252
Prior service credit	**---**	(1,140)	**(2,438)**	(3,151)
Total	**$ 45,408**	$ 43,874	**$ 9,902**	$ 12,101

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Amounts recognized in regulatory assets (liabilities) in the above table are expected to be reflected in rates charged to customers over time. For more information on regulatory assets (liabilities) see Note 3.

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets was amortized on a straight-line basis over the average life expectancy of plan participants. The market-related value of assets is determined using a five-year average of assets.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plan, of which all have an accumulated benefit obligation in excess of plan assets for the years ended December 31 were as follows:

	2012	2011
	(In thousands)	
Projected benefit obligation	**$ 92,987**	$87,104
Accumulated benefit obligation	**$ 92,987**	$87,104
Fair value of plan assets	**$ 62,714**	$55,011

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	**2012**	2011
		(In thousands)		
Components of net periodic benefit cost (credit):				
Service cost	**$ 939**	$ 1,075	**$ 197**	$ 151
Interest cost	**3,473**	3,752	**912**	1,103
Expected return on assets	**(4,602)**	(4,002)	**(1,101)**	(1,172)
Amortization of prior service credit	**(117)**	(156)	**(713)**	(2,302)
Curtailment gain	**(1,023)**	---	**---**	---
Recognized net actuarial loss	**2,926**	2,628	**1,103**	806
Net periodic benefit cost (credit)	**1,596**	3,297	**398**	(1,414)
Other changes in plan assets and benefit obligations recognized in regulatory assets:				
Net (gain) loss	**3,320**	17,603	**(1,809)**	4,372
Amortization of actuarial loss	**(2,926)**	(2,628)	**(1,103)**	(806)
Amortization of prior service credit	**1,140**	156	**713**	2,302
Total recognized in regulatory assets	**1,534**	15,131	**(2,199)**	5,868
Total recognized in net periodic benefit cost and regulatory assets	**$ 3,130**	$ 18,428	**$ (1,801)**	$ 4,454

The estimated net loss for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost in 2013 is $1.4 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from regulatory assets into net periodic benefit cost in 2013 are $1.0 million and $242,000, respectively.

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	**2012**	2011
Discount rate	**3.68%**	4.15%	**3.65%**	4.12%
Expected return on plan assets	**7.00%**	7.75%	**6.00%**	6.75%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	**2012**	2011
Discount rate	**3.62%**	5.25%	**4.12%**	5.20%
Expected return on plan assets	**7.75%**	7.75%	**6.75%**	6.75%

The expected rate of return on pension plan assets is based on the targeted asset allocation range of 60 percent to 70 percent equity securities and 30 percent to 40 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement assets is based on the targeted asset allocation range of 65 percent to 75 percent equity securities and 25 percent to 35 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2012	2011
Health care trend rate assumed for next year	**7.5%**	8.0%
Health care cost trend rate – ultimate	**5.0%**	5.0%
Year in which ultimate trend rate achieved	**2017**	2017

The Company's other postretirement benefit plans include health care benefits for certain retirees. The plans underlying these benefits may require contributions by the retiree depending on such retiree's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over six percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2012:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 79	$ (68)
Effect on postretirement benefit obligation	$ 1,908	$ (1,646)

The Company's pension assets are managed by 14 outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and future contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs.

The estimated fair values of the Company's pension plan assets are determined using the market approach.

The carrying value of the pension plans' Level 1 and Level 2 cash equivalents approximates fair value and is determined using observable inputs in active markets or the net asset value of shares held at year end, which is determined using other observable inputs including pricing from outside sources. Units of this fund can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in high quality, short-term instruments of domestic and foreign issuers.

The estimated fair value of the pension plans' Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded.

The estimated fair value of the pension plans' Level 1 and Level 2 collective and mutual funds are based on the net asset value of shares held at year end, based on either published market quotations on active markets or other known sources including pricing from outside sources.

The estimated fair value of the pension plans' Level 2 corporate and municipal bonds is determined using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, future cash flows and other reference data.

The estimated fair value of the pension plans' Level 1 U.S. Treasury securities are valued based on quoted prices on an active market.

The estimated fair value of the pension plans' Level 2 U.S. Treasury and mortgage-backed securities are valued mainly using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, to be announced prices, future cash flows and other reference data. Some of these securities are valued using pricing from outside sources.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2012 and 2011, there were no transfers between Levels 1 and 2.

The fair value of the Company's pension net plan assets by class is as follows:

	Fair Value Measurements at December 31, 2012, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2012
		(In thousands)		
Assets:				
Cash equivalents	$ 435	$ 2,122	$ ---	$ 2,557
Equity securities:				
U.S. companies	17,643	---	---	17,643
International companies	8,077	---	---	8,077
Collective and mutual funds*	16,792	4,070	---	20,862
Corporate bonds	---	9,150		9,150
Municipal bonds	---	1,887	---	1,887
U.S. Treasury securities	1,619	919	---	2,538
Total assets measured at fair value	$ 44,566	$ 18,148	$ ---	$ 62,714

* *Collective and mutual funds invest approximately 12 percent in common stock of mid-cap U.S. companies, 26 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 41 percent in corporate bonds and 8 percent in other investments.*

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
		(In thousands)		
Assets:				
Cash equivalents	$ 446	$ 3,470	$ ---	$ 3,916
Equity securities:				
U.S. companies	19,653	---	---	19,653
International companies	6,996	---	---	6,996
Collective and mutual funds *	8,551	3,075	---	11,626
Corporate bonds	---	4,666	57	4,723
Mortgage-backed securities	---	4,549	---	4,549
Municipal bonds	---	1,838	---	1,838
U.S. Treasury securities	---	1,710	---	1,710
Total assets measured at fair value	$ 35,646	$ 19,308	$ 57	$ 55,011

* *Collective and mutual funds invest approximately 26 percent in common stock of mid-cap U.S. companies, 26 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 6 percent in corporate bonds and 29 percent in other investments.*

The following table sets forth a summary of changes in the fair value of the pension plans' Level 3 assets for the year ended December 31, 2012:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)
	Corporate Bonds
	(In thousands)
Balance at beginning of year	$ 57
Total realized/unrealized losses	(9)
Purchases, issuances and settlements (net)	(48)
Balance at end of year	$ ---

The following table sets forth a summary of changes in the fair value of the pension plans' Level 3 assets for the year ended December 31, 2011:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Corporate Bonds	Collateral Held on Loaned Securities	Total
	(In thousands)		
Balance at beginning of year	$ ---	$ 131	$ 131
Total realized/unrealized losses	---	(46)	(46)
Purchases, issuances and settlements (net)	57	(85)	(28)
Balance at end of year	$ 57	$ ---	$ 57

The estimated fair values of the Company's other postretirement benefit plan assets are determined using the market approach.

The estimated fair value of the other postretirement benefit plan's Level 1 and Level 2 cash equivalents is valued at the net asset value of shares held at year end, based on published market quotations on active markets, or using other known sources including pricing from outside sources. Units of this fund can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in high-quality, short-term money market instruments that consist of municipal obligations.

The estimated fair value of the other postretirement benefit plan's Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded.

The estimated fair value of the other postretirement benefit plan's Level 2 insurance investment contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2012 and 2011, there were no transfers between Levels 1 and 2.

The fair value of the Company's other postretirement benefit plan assets by asset class is as follows:

	Fair Value Measurements at December 31, 2012, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2012
			(In thousands)	
Assets:				
Cash equivalents	$ 270	$ 475	$ ---	$ 745
Equity securities:				
U.S. companies	1,346	---	---	1,346
International companies	260	---	---	260
Insurance investment contract*	---	15,429	---	15,429
Total assets measured at fair value	$ 1,876	$ 15,904	$ ---	$ 17,780

** The insurance investment contract invests approximately 51 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 10 percent in mortgage-backed securities, 11 percent in corporate bonds, and 13 percent in other investments.*

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
			(In thousands)	
Assets:				
Cash equivalents	$ 59	$ 511	$ ---	$ 570
Equity securities:				
U.S. companies	1,293	---	---	1,293
International companies	262	---	---	262
Insurance investment contract*	---	14,954	---	14,954
Total assets measured at fair value	$ 1,614	$ 15,465	$ ---	$ 17,079

** The insurance investment contract invests approximately 49 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 12 percent in mortgage-backed securities, 11 percent in corporate bonds, and 13 percent in other investments.*

The Company expects to contribute approximately $4.0 million to its defined benefit pension plan and approximately $825,000 to its postretirement benefit plans in 2013.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2013	$ 4,292	$ 1,566	$ 5
2014	4,403	1,573	5
2015	4,453	1,587	4
2016	4,588	1,559	4
2017	4,698	1,555	4
2018-2022	25,649	7,001	12

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans at Cascade and Intermountain for certain executive officers. Cascade's plan provides for defined benefit payments following the employee's retirement or to their beneficiaries upon death for up to a 10-year period, plus the surviving spouse is entitled to receive a monthly benefit for life equal to one-half of the benefit the participant was entitled to before death. Effective October 1, 2003, the plan was amended so that no new participants will be added to the plan and no additional benefits will accrue for existing participants. Intermountain's plan provides for defined benefit payments following the employee's retirement until death for a minimum of a 20-year period or to their beneficiaries upon pre-retirement death for a 10-year period equal to twice the benefit the participant was entitled to before death. The Company had investments of $9.7 million and $9.4 million at December 31, 2012 and 2011, respectively, consisting of equity securities of $1.9 million and $1.8 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $6.4 million and $6.7 million, respectively, and other investments of $1.4 million and $975,000, respectively, which the Company anticipates using to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was $1.2 million for both 2012 and 2011. The total projected benefit obligation for these plans was $15.6 million and $15.1 million at December 31, 2012 and 2011, respectively. The accumulated benefit obligation for these plans was $15.6 million and $15.0 million at December 31, 2012 and 2011, respectively. A weighted average discount rate of 3.4 percent and 4.0 percent at December 31, 2012 and 2011, respectively, was used to determine benefit obligations. A discount rate of 3.9 percent and 5.0 percent at December 31, 2012 and 2011, respectively, and a rate of compensation increase of 4.0 percent at both December 31, 2012 and December 31, 2011, was used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans, as appropriate, are expected to aggregate $1.0 million in 2013; $932,000 in 2014; $926,000 in 2015; $1.0 million in 2016; $1.0 million in 2017; and $5.2 million for the years 2018 through 2022.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Costs incurred under this plan for 2012 were $18,000.

Defined contribution plans
The Company sponsors various defined contribution plans for eligible employees and the costs incurred by the Company under these plans were $1.6 million in both 2012 and 2011.

Multiemployer plans
Intermountain contributes to a multiemployer defined benefit pension plan under the terms of a collective-bargaining agreement that covers its union-represented employees. The risks of participating in a multiemployer plan are different from a single-employer plan in the following aspects:

- Assets contributed to the multiemployer plan by one employer may be used to provide benefits to employees of other participating employers
- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers
- If the Company chooses to stop participating in the multiemployer plan, the Company may be required to pay the plan an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in this plan is outlined in the following table. The most recent Pension Protection Act zone status available in 2012 and 2011 is for the plan's year-end at December 31, 2011, and December 31, 2010, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded.

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status 2012	Pension Protection Act Zone Status 2011	FIP/RP Status Pending/Implemented	Contributions 2012	Contributions 2011	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)			
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2012	Green as of 5/31/2011	No	**$ 1,085**	$ 1,063	No	09/30/2013

Intermountain was listed in the Idaho Plumbers and Pipefitters Pension Plan's Form 5500 as providing more than 5 percent of the total contributions as of the plan's year-end of December 31, 2011 and 2010, respectively.

NOTE 10 – COMMITMENTS AND CONTINGENCIES

Claims and Litigation

The Company accrues a liability for contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, where feasible, an estimate of the possible loss. The Company had accrued liabilities of $14.5 million and $6.9 million for contingencies related to litigation and environmental matters as of December 31, 2012 and 2011, respectively, which includes amounts that may have been accrued for matters discussed in Environmental matters within this note.

Regulatory matters

Natural Gas Distribution The WUTC on March 21, 2011, filed a complaint against Cascade, alleging pipeline safety violations in the operation of its natural gas distribution system. The complaint alleged more than 360 violations of pipeline safety regulations and sought relief including unspecified monetary penalties. Cascade filed its answer to the complaint admitting some and denying other of the alleged violations. Cascade and the WUTC staff entered into a settlement agreement filed with the WUTC on July 13, 2011, which was approved by the WUTC on August 3, 2011. The settlement provided for an immediate cash payment by Cascade of $425,000 and suspended penalties totaling up to $1.8 million which Cascade would have be required to pay if it had failed to comply with action items for remediation of violations and implementation of safety program improvements within timelines specified in the agreement. The Company's leadership is committed to pipeline safety compliance and substantial resources have been invested by Cascade to improve pipeline safety documentation and procedures. Cascade recognized certain compliance issues and worked with the WUTC to become fully compliant. All of the violations have been remedied and significant additional technological and other investments have been made to comply with the requirements of the settlement agreement and improve compliance procedures and results.

Environmental matters

Manufactured Gas Plant Sites There are three claims against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors.

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. The Oregon State Department of Environmental Quality is preparing a staff report which will recommend a cleanup alternative for the site. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has accrued $1.3 million for remediation of this site. In November 2012, Cascade filed a petition with the OPUC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until November 30, 2013. The OPUC approved the petition in January 2013.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. The EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In May 2012, the EPA added the site to the National Priorities List. Cascade is in discussions with the EPA regarding an administrative settlement agreement and consent order with the intent of reaching consensus on the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $6.7 million for the remedial investigation and feasibility study and $6.4 million for remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

The third claim is for contamination at a site in Bellingham, Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade and its predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. Other PRPs have reached an agreed order and work plan with the Washington Department of Ecology for completion of a remedial investigation and feasibility study for the site. A report documenting the initial phase of the remedial investigation was completed in June 2011. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim although Cascade believes its proportional share of any liability will be relatively small in comparison to other PRPs. The plant manufactured gas from coal between approximately 1890 and 1946. In 1946, shortly after Cascade's predecessor acquired the plant, it converted the plant to a propane-air gas facility. There are no documented wastes or by-products resulting from the mixing or distribution of propane-air gas.

Cascade has received notices from certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

The accruals related to these matters are reflected in regulatory assets. For more information, see Note 3.

Operating leases
The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2012, were $1.0 million in 2013, $216,000 in 2014, $181,000 in 2015, $140,000 in 2016, $71,000 in 2017, and $268,000 thereafter. Rent expense was $353,000 and $345,000 for the years ended December 31, 2012 and 2011, respectively.

Purchase commitments
The Company has entered into various commitments, largely natural gas supply and natural gas transportation and storage contracts. These commitments range from one to 48 years. The commitments under these contracts as of December 31, 2012, were $239.4 million in 2013, $191.9 million in 2014, $99.6 million in 2015, $53.8 million in 2016, $53.6 million in 2017, and $832.6 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2012 and 2011, respectively, were approximately $253.8 million and $299.9 million.

NOTE 11 – RELATED-PARTY TRANSACTIONS
MDU and Montana-Dakota provide and receive certain support services to/from the Company. The amount charged for services provided to the Company was $32.3 million and $26.6 million for the years ended December 31, 2012 and 2011, respectively and the amount charged for services received from the Company was $332,000 and $354,000 for the years ended December 31, 2012 and 2011, respectively.

The amounts included in the Consolidated Balance Sheets related to MDU and Montana-Dakota as of December 31 are as follows:

	2012	2011
	(In thousands)	
Accounts receivable	**$ 69**	$ 53
Accounts payable	**2,429**	2,871
Dividend payable	**---**	5,000

MDU has several stock-based compensation plans in which the Company participates. Total stock-based compensation expense for the years ended December 31, 2012 and 2011, respectively, was $644,000 and $565,000, net of income taxes of $412,000 and $361,000, respectively. As of December 31, 2012, total remaining unrecognized compensation expense related to stock-based compensation was approximately $918,000 (before income taxes) which will be amortized over a weighted average period of 1.5 years.

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec 31, 2012**

Summary of Utility Plant and Accumulated Provisions For Depreciation, Amortization, and Depletion

Line No.	Item (a)	Total Company For the Current Quarter/Year
1	UTILITY PLANT	
2	In Service	
3	Plant in Service (Classified)	737,323,182
4	Property under Capital Leases	-
5	Plant Purchased or Sold	-
6	Completed Construction not Classified	-
7	Experimental Plant Unclassified	-
8	TOTAL Utility Plant (Total of lines 3 thru 7)	737,323,182
9	Leased to Others	-
10	Held for Future Use	-
11	Construction Work in Progress	17,556,051
12	Acquisition Adjustments	-
13	Total Utility Plant (Total of Lines 8 thru 12)	754,879,233
14	Accumulated Provisions For Depreciation, Amortization, & Depletion	(372,642,118)
15	Net Utility Plant (Total of Line 13 less 14)	382,237,115
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION, AND DEPLETION	
17	In Service:	
18	Depreciation	(370,805,535)
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights	-
20	Amortization of Underground Storage Land and Land Rights	-
21	Amortization of Other Utility Plant	(1,836,583)
22	Total In-Service (Total of Lines 18 thru 21)	(372,642,118)
23	Leased to Others	
24	Depreciation	-
25	Amortization and Depletion	-
26	TOTAL Leased to Others (Total of Lines 24 and 25)	-
27	Held for future Use	
28	Depreciation	-
29	Amortization	-
30	TOTAL Held for Future Use (Total of Lines 28 and 29)	-
31	Abandonment of Leases (Natural Gas)	-
32	Amortization of Plant Acquisition Adjustments	-
33	Total Accumulated Provisions (Should agree with line 14 above)(Total of lines 22, 26, 30, 31, and 32)	(372,642,118)

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec 31, 2012**

Summary of Utility Plant and Accumulated Provisions For Depreciation, Amortization, and Depletion (Continued)

Line No.	Electric (c)	Gas (d)	Other (specify) (e)	Common (f)
1				
2				
3	-	737,323,182		
4	-			
5	-			
6	-			
7	-			
8	-	737,323,182	-	-
9	-	-		
10	-	-		
11	-	17,556,051		
12		-		
13	-	754,879,233	-	-
14	-	(372,642,118)		
15	-	382,237,115	-	-
16				
17				
18		(370,805,535)		
19				
20				
21		(1,836,583)		
22	-	(372,642,118)	-	-
23				
24				
25				
26	-	-	-	-
27				
28				
29				
30	-	-	-	-
31				
32				
33	-	(372,642,118)	-	-

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec 31, 2012**

GAS PLANT IN SERVICE (Accounts 101, 102, 103 and 106)

1. Report below the original cost of gas plant in service according to the prescribed accounts.
2. In addition to Account 101, Gas Plant in Service (Classified), this page and the next include Account 102, Gas Plant Purchased or Sold, Account 103, Experimental Gas Plant Unclassified, and Account 106, Completed Construction Not Classified-Gas.
3. Include in column (c) and (d), as appropriate corrections of additions and retirements for the current or preceding year.
4. Enclose in parenthesis credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c).Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year's unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d),

Line No.		Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	INTANGIBLE PLANT			
2	301	Organization	152,066	0
3	302	Franchises and Consents	211,825	0
4	303	Miscellaneous Intangible Plant	12,273,071	4,721,593
5		TOTAL Intangible Plant (Enter Total of lines 2 thru 4)	12,636,962	4,721,593
6	PRODUCTION PLANT			
7		Natural Gas Production and Gathering Plant		
8	325.1	Producing Lands	0	0
9	325.2	Producing Leaseholds	0	0
10	325.3	Gas Rights	0	0
11	325.4	Rights-of-Way	0	0
12	325.5	Other Land and Land Rights	0	0
13	326	Gas Well Structures	0	0
14	327	Field Compressor Station Structures	0	0
15	328	Field Measuring and Regulating Station Equipment	0	0
16	329	Other Structures	0	0
17	330	Producing Gas Wells - Well Construction	0	0
18	331	Producing Gas Wells - Well Equipment	0	0
19	332	Field Lines	0	0
20	333	Field Compressor Station Equipment	0	0
21	334	Field Measuring and Regulating Station Equipment	0	0
22	335	Drilling and Cleaning Equipment	0	0
23	336	Purification Equipment	0	0
24	337	Other Equipment	0	0
25	338	Unsuccessful Exploration and Development Costs	0	0
26	339	Asset Retirement Costs for Natural Gas Production and	0	0
27		TOTAL Production and Gathering Plant	0	0
28	PRODUCTS EXTRACTION PLANT			
29	340	Land and Land Rights	0	0
30	341	Structures and Improvements	0	0
31	342	Extraction and Refining Equipment	0	0
32	343	Pipe Lines	0	0
33	344	Extracted Product Storage Equipment	0	0

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec 31, 2012

GAS PLANT IN SERVICE (Accounts 101, 102, 103 and 106) (continued)

including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Account 101 and 106 will avoid serious omissions of respondent's reported amount for plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give date of such filing.

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1				
2	0	0	0	152,066
3	0	0	0	211,825
4	0	0	0	16,994,664
5	0.00	0.00	0.00	17,358,555
6				
7				
8	0	0	0	0
9	0	0	0	0
10	0	0	0	0
11	0	0	0	0
12	0	0	0	0
13	0	0	0	0
14	0	0	0	0
15	0	0	0	0
16	0	0	0	0
17	0	0	0	0
18	0	0	0	0
19	0	0	0	0
20	0	0	0	0
21	0	0	0	0
22	0	0	0	0
23	0	0	0	0
24	0	0	0	0
25	0	0	0	0
26	0	0	0	0
27	0	0	0	0
28				
29	0	0	0	0
30	0	0	0	0
31	0	0	0	0
32	0	0	0	0
33				0

Name of Respondent Cascade Natural Gas Corporation	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year Ending **Dec 31, 2012**

GAS PLANT IN SERVICE (Accounts 101, 102, 103 and 106)

Line No.		Account (a)	Balance at Beginning of Year (b)	Additions (c)
34	345	Compressor Equipment	0	0
35	346	Gas Measuring and Regulating Equipment	0	0
36	347	Other Equipment	0	0
37	348	Asset Retirement Costs for Products Extraction Plant	0	0
38		TOTAL Products Extraction Plant (Total Lines 29 thru 37)	0	0
39		TOTAL Natural Gas Production Plant (Total line 27 and 38)	0	0
40	Manufactured Gas Production Plant (Submit Supplementary		0	0
41		TOTAL Production Plant (Total of lines 39 and 40)	0	0
42	NATURAL GAS STORAGE AND PROCESSING PLANT			
43	Underground Storage Plant			
44	350.1	Land	0	0
45	350.2	Rights-of-Way	0	0
46	351	Structures and Improvements	0	0
47	352	Well	0	0
48	352.1	Storage Leaseholds and Rights	0	0
49	352.2	Reservoirs	0	0
50	352.3	Non-recoverable Natural Gas	0	0
51	353	Lines	0	0
52	354	Compressor Station Equipment	0	0
53	355	Other Equipment	0	0
54	356	Purification Equipment	0	0
55	357	Other Equipment	0	0
56	358	Asset Retirement Costs for Underground Storage Plant	0	0
57		TOTAL Underground Storage Plant (enter total of lines 44 thru 56)	0	0
58	Other Storage Plant			
59	360	Land and Land Rights	0	0
60	361	Structures and Improvements	0	0
61	362	Gas Holders	0	0
62	363	Purification Equipment	0	0
63	363.1	Liquefaction Equipment	0	0
64	363.2	Vaporizing Equipment	0	0
65	363.3	Compressor Equipment	0	0
66	363.4	Measuring and Regulating Equipment	0	0
67	363.5	Other Equipment	0	0
68	363.6	Asset Retirement Costs for Other Storage Plant	0	0
69		TOTAL Other Storage Plant (Enter Total of lines 58-68)	0	0
70	Base Load Liquefied Nat. Gas Terminating & Proc			
71	364.1	Land and Land Rights	0	0
72	364.2	Structures and Improvements	0	0
73	364.3	LNG Processing Terminal Equipment	0	0
74	364.4	LNG Transportation Equipment	0	0
75	364.5	Measuring and Regulating Equipment	0	0
76	364.6	Compressor Station Equipment	0	0
77	364.7	Communications Equipment	0	0
78	364.8	Other Equipment	0	0
79	364.9	Asset Retirement Costs for Base Load Liquefied Nat Gas	0	0
80	TOTAL Base Load Liq. Nat. Gas Terminating & Pr		0	0

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year Ending **Dec 31, 2012**

GAS PLANT IN SERVICE (Accounts 101, 102, 103 and 106) (continued)

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
34	0	0	0	0
35	0	0	0	0
36	0	0	0	0
37	0	0	0	0
38	0	0	0	0
39	0	0	0	0
40	0	0	0	0
41	0	0	0	0
42				
43				
44	0	0	0	0
45	0	0	0	0
46	0	0	0	0
47	0	0	0	0
48	0	0	0	0
49	0	0	0	0
50	0	0	0	0
51	0	0	0	0
52	0	0	0	0
53	0	0	0	0
54	0	0	0	0
55	0	0	0	0
56	0	0	0	0
57	0	0	0	0
58				
59	0	0	0	0
60	0	0	0	0
61	0	0	0	0
62	0	0	0	0
63	0	0	0	0
64	0	0	0	0
65	0	0	0	0
66	0	0	0	0
67	0	0	0	0
68	0	0	0	0
69	0	0	0	0
70				
71	0	0	0	0
72	0	0	0	0
73	0	0	0	0
74	0	0	0	0
75	0	0	0	0
76	0	0	0	0
77	0	0	0	0
78	0	0	0	0
79	0	0	0	0
80	0	0	0	0

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec 31, 2012**

GAS PLANT IN SERVICE (Accounts 101, 102, 103 and 106)

Line No.		Account (a)	Balance at Beginning of Year (b)	Additions (c)
81		TOTAL Nat'l Gas Storage and Processing Plant (Total of 57,	0	0
82	TRANSMISSION PLANT			
83	365.1	Land and land rights	224,536	0
84	365.2	Rights-of-way	1,026,089	0
85	366	Structures and improvements	0	0
86	367	Mains	15,829,354	0
87	368	Compressor station equipment	0	0
88	369	Measuring and regulating station equipment	205,099	0
89	370	Communication equipment	0	0
90	371	Other equipment	0	0
91	372	Asset Retirement Costs for Transmission Plant	0	0
92		TOTAL Transmission Plant (Total lines 83 thru 91)	17,285,078	0
93	DISTRIBUTION PLANT			
94	374	Land and land rights	2,436,518	53,728
95	375	Structures and improvements	1,420,458	0
96	376	Mains	328,257,812	21,241,930
97	377	Compressor station equipment	2,000,731	0
98	378	Measuring and regulating equipment - General	18,545,387	1,572,978
99	379	Measuring and regulating equipment - City gate	0	0
100	380	Services	177,442,653	4,051,428
101	381	Meters	46,651,742	674,130
102	382	Meter installations	29,571,585	165,059
103	383	House regulators	9,471,286	403,682
104	384	House regulator installations	0	0
105	385	Industrial measuring and regulating station equipment	7,440,558	314,331
106	386	Other property on customers' premises	0	0
107	387	Other equipment	0	0
108	388	Retirement Costs for Distribution Plant	45,332	0
109		TOTAL Distribution Plant (Enter total of lines 94 thru 108)	623,284,062	28,477,266
110	GENERAL PLANT			
111	389	Land and land rights	2,253,273	0
112	390	Structures and improvements	17,025,492	43,073
113	391	Office furniture and Equipment	10,307,580	106,561
114	392	Transportation equipment	8,943,543	2,038,508
115	393	Stores equipment	69,362	0
116	394	Tools, shop and garage equipment	4,703,836	605,660
117	395	Laboratory equipment	138,043	0
118	396	Power operated equipment	2,027,995	786,145
119	397	Communication equipment	4,157,470	297,893
120	398	Miscellaneous equipment	22,067	35,655
121		Subtotal (Total of lines 111 thru 120)	49,648,661	3,913,495
122	399	Other Tangible Property	0	0
123	399.1	Asset Retirement Costs for General Plant	0	0
124		TOTAL General Plant (Total lines 121, 122, and 123)	49,648,661	3,913,495
125		TOTAL (Accounts 101 and 106)	702,854,763	37,112,354
126		Gas plant purchased (See Instruction 8)	0	0
127		(Less) Gas plant sold (See Instruction 8)	0	
128		Experimental gas plant unclassified	0	0
129		TOTAL Gas Plant In Service (Enter Total of lines 125 thru 128)	**702,854,763**	**37,112,354**

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec 31, 2012**

GAS PLANT IN SERVICE (Accounts 101, 102, 103 and 106) (continued)

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
81	0	0	0	0
82				
83	0	0	0	224,536
84	0	0	0	1,026,089
85	0	0	0	0
86	(29,892)	0	0	15,799,462
87	0	0	0	0
88	0	0	0	205,099
89	0	0	0	0
90	0	0	0	0
91	0	0	0	0
92	(29,892)	0	0	17,255,186
93				
94	0	0	0	2,490,246
95	0	0	0	1,420,458
96	(425,501)	0	0	349,074,241
97	0	0	0	2,000,731
98	(101,231)	0	0	20,017,134
99	0	0	0	0
100	(121,323)	0	0	181,372,758
101	(206,200)	0	0	47,119,672
102	(17,493)	0	0	29,719,151
103	(130,110)	0	0	9,744,858
104	0	0	0	0
105	(5,842)	0	0	7,749,047
106	0	0	0	0
107	0	0	0	0
108	0	0	0	45,332
109	(1,007,700)	0	0	650,753,628
110				
111	0	0	0	2,253,273
112	0	0	0	17,068,565
113	(686,786)	0	0	9,727,355
114	(382,742)	0	0	10,599,309
115	0	0	0	69,362
116	(33,967)	0	0	5,275,529
117	0	0	0	138,043
118	(444,437)	0	0	2,369,703
119	(58,411)	0	0	4,396,952
120	0	0	0	57,722
121	(1,606,343)	0	0	51,955,813
122	0	0	0	0
123	0	0	0	0
124	(1,606,343)	0	0	51,955,813
125	(2,643,935)	0	0	737,323,182
126		0	0	0
127	0	0	0	0
128	0	0	0	0
129	**(2,643,935)**	**0**	**0**	**737,323,182**

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

GAS PROPERTY AND CAPACITY LEASED FROM OTHERS

1. Report below the information called for concerning gas property and capacity leased from others for gas operations.
2. For all leases in which the average annual lease payment over the initial term of the lease exceeds $500,000, described in column (c), if applicable, the property or capacity leased. Designate associated companies with an asterisk in column (b).

Line No.	Name of Lessor (a)	* (b)	Description of Lease (c)	Lease Payments For Current Year (d)
1	None			
2				
3				
4				
5				
6				
7				
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45	**TOTAL -**			

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

GAS PROPERTY AND CAPACITY LEASED TO OTHERS

1. For all leases in which the average lease income over the initial term of the lease exceeds $500,000, provide in column (c) a description of each facility or leased capacity that is classified as gas plant in service, and is leased to others for gas operations.
2. In column (d) provide the lease payments received from others.
3. Designate associated companies with an asterisk in column (b).

Line No.	Name of Lessor (a)	* (b)	Description of Lease (c)	Lease Payments For Current Year (d)
1	None			
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7				
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45	**TOTAL -**			

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

GAS PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $1,000,000 or more. Group other items of property held for future use.
2. For property having an original cost of $1,000,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in this Account (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	None			
2				
3				
4				
5				
6				
7				
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45	**TOTAL -**			

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

CONSTRUCTION WORK IN PROGRESS - GAS (Account 107)

1. Report below descriptions and balances at end of year or project in process of construction (Account 107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Acctount 107 of the Uniform System of Accounts).
3. Minor projects (less than $1,000,000) may be grouped.

Line No.	Description of Project (a)	Construction Work in Progress - Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	Bend Bare Pipe replacement 2" Plastic Main	1,172,112	
2	Purchase Power Plan Direct Costs	1,363,896	
3	Preliminary Hanford DOE - Main	1,816,275	
4			
5			
6			
7			
8	Minor distribution system/general plant projects each under $1 million	13,203,768	
9			
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44			
45	**TOTAL -**	17,556,051	-

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec. 31, 2012

Non-Traditional Rate Treatment Afforded New Projects

1. The Commission's Certificate Policy Statement provides a threshold requirement for existing pipelines proposing new projects is that the pipeline must be prepared to financially support the project without relying on subsidization from its existing customers. See Certification of New Interstate Natural Gas Pipeline Facilities, 88 FERC P61,227 (1999); order clarifying policy, 90 FERC P61,128 (2000); order clarifying policy, 92 FERC P61,094 (2000) (Policy Statement). In column a, list the name of the facility granted non-traditional rate treatment.
2. In column b, list the CP Docket Number where the Commission authorized the facility.
3. In column c, indicate the type of rate treatment approved by the Commission (e.g. incremental, at risk)
4. In column d, list the amount in Account 101, Gas Plant in Service, associated with the facility.
5. In column e, list the amount in Account 108, Accumulated Provision for Depreciation of Gas Utility Plant, associated with the facility.

Line No	Name of Facility (a)	CP Docket No. (b)	Type of Rate Treatment (c)	Gas Plant in Service (d)
1	None			
2				
3				
4				
5				
6				
7				
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34				
35				
36				
	Total			

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report Dec. 31, 2012

Non-Traditional Rate Treatment Afforded New Projects (continued)

6. In column f, list the amount in Account 190, Accumulated Deferred Income Tax; Account 281, Accumulated Deferred Income Taxes – Accelerated Amortization Property; Account 282, Accumulated Deferred Income Taxes – Other Property; Account 283, Accumulated Deferred Income Taxes – Other, associated with the facility.
7. In column g, report the total amount included in the gas operations expense accounts during the year related to the facility (Account 401, Operation Expense).
8. In column h, report the total amount included in the gas maintenance expense accounts during the year related to the facility.
9. In column i, report the amount of depreciation expense accrued on the facility during the year.
10. In column j, list any other expenses(including taxes) allocated to the facility.
11. In column k, report the incremental revenues associated with the facility.
12. Identify the volumes received and used for any incremental project that has a separate fuel rate for that project.
13. Provide the total amounts for each column.

Line No	Accumulated Depreciation (e)	Accumulated Deferred Income Taxes (f)	Operating Expense (g)	Maintenance Expense (h)	Depreciation Expense (i)	Other Expenses (including taxes) (j)	Incremental Revenues (k)
1							
2							
3							
4							
5							
6							
7							
8							
9							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec 31, 2012**

GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE

1. For each construction overhead, explain: (a) the nature and extent of work, etc., that the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.
2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Gas Plant Instructions 3 (17) of the Uniform System of Accounts.
3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

1. Engineering & Supervision and General & Administrative overhead:

Engineer & Supervision (ES) overhead consists of employees' time in preparation of work orders, mapping, determining feasibility, and other Engineering/construction based supervisory costs related to new construction which are not identified with a specific project, along with the associated payroll taxes and employee benefit costs.

General & Administrative (GA) overhead consists of employees' time in processing A/P, A/R, receiving orders,and other administrative functions which are not identified with a

Both ES & GA (ES/GA) are accumulated in pools from which a portion is allocated each month. The allocation is based on a rate determined by the Manager of General &

2. ALLOWANCE FOR BORROWED FUNDS USED DURING CONSTRUCTION (AFUDC):
The formula on page 218a is used.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year Ending
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GENERAL DESCRIPTION OF CONSTRUCTION OVERHEAD PROCEDURE (continued)

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

1. For line 1(5), column (d) below, enter the rate granted in the last rate proceeding. If such is not available, use the average rate earned during the preceding three years
2. Identify, in a footnote, the specific entity used as the source for the capital structure figures.
3. Indicate, in a footnote, if the reported rate of return is one that has been approved in a rate case, black-box settlement rate, or an actual three-year average rate.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No	Title (a)		Amount (b)	Capitalization Ratio (%) (c)	Cost Rate Percentage (d)		
	(1) Average Short-Term Debt	S	0				
	(2) Short-Term Interest				s	0.00%	
	(3) Long-Term Debt	D	158,154,890	48.4%	d	7.01%	
	(4) Preferred Stock	P	0		p	0.00%	
	(5) Common Equity	C	168,712,762	51.6%	c	10.58%	
	(6) Total Capitalization		326,867,652	100.0%			
	(7) Average Construction Work In Progress Balance	W	$ 15,906,498				

2. Gross Rate for Borrowed Funds	s (S/W) + d[(D/(D+P+C)) (1 - S/W))]	3.39%
3. Rate for Other Funds	[1 - S/W] [p (P/(D+P+C)) + c (C/(D+P+C))]	5.46%

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 3.39%

b. Rate for Other Funds - 5.46%

Name of Respondent	This Report is:	Date of Report	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

ACCUMULATED PROVISION FOR DEPRECIATION OF GAS UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, line 10, column (c), and that reported for gas plant in service, pages 204-209, column (d) excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of Accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classification, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include allcosts included in retirement work in progress at year endin the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.
5. At lines 7 and 14, add rows as necessary to report all data. Additional rows should be numbered in sequences, e.g., 7.01, 7.02, etc.

Section A. Balances and Changes During the Year

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant In-Service (c)	Gas Plant Held For Future Use (d)	Gas Plant Leased to Others (e)
	Section A. BALANCES AND CHANGES DURING YEAR				
1	Balance Beginning of Year	(354,315,004)	(354,315,004)	-	-
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	(18,451,177)	(18,451,177)		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-			
5	(413) Expense of Gas Plant Leased to Others	-			
6	Transportation Expenses-Cleaning	(859,066)	(859,066)		
7	Other clearing accounts	-			
8	Other Clearing (specify) (footnote details):	-			
8.01	ARO Assets	(2,059)	(2,059)		
9					
10	TOTAL Deprec. Provisions for the Year (Total of lines 3 thru 8)	(19,312,302)	(19,312,302)	-	-
11	Net Charges for Plant Retired:				
12	Book cost of plant retired	2,643,935	2,643,935		
13	Cost of Removal	807,221	807,221		
14	Salvage (credit)	(353,851)	(353,851)		
15	TOTAL Net Charges for Plant Retired (Total of lines 12 thru 14)	3,097,305	3,097,305	-	-
16	Other Debit or Credit Items (Describe) (footnote datails):				
16.01	Increase/Decrease in RWIP	(275,534)	(275,534)		
16.02	Other Debits/Credits	-			
17					
18	Book Cost of Asset Retirement Costs				
19	BALANCE End of Year (Total oflines 1, 10,15,16 and 18)	(370,805,535)	(370,805,535)	-	-
	Section B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS				
21	Production - Manufactured Gas	-			
22	Production and Gathering - Natural Gas	-			
23	Products Extraction - Natural Gas	-			
24	Underground Gas Storage	-			
25	Other Storage Plant	-			
26	Base Load LNG Terminalling & Processing Plant	-			
27	Transmission	(10,337,309)	(10,337,309)		
28	Distribution	(331,934,345)	(331,934,345)		
29	General	(28,143,895)	(28,143,895)		
29.1	Intangible Plant	(211,825)	(211,825)		
29.2	Retirement work-in-progress	(178,161)	(178,161)		
30	TOTAL (Enter Total of lines 21 thru 31)	(370,805,535)	(370,805,535)	-	-

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec. 31, 2012

GAS STORED (Account 117.1, 117.2, 117.3, 117.4, 164.1, 164.2 and 164.3)

1 If during the year adjustments were made to the stored gas inventory reported in columns (d), (f), (g), and (h) (such as the correct cumulative inaccuracies of gas measurements), explain in a footnote the reason for the adjustments, the Dth and dollar amount of adjustment, and account charged or credited.

2. Report in column (e) all encroachments during the year upon the volumes designated as base gas, column (b), and system balancing gas, column (c), and gas property recordable in the plant accounts.

3. State in a footnote the basis of segregation of inventory between current and noncurrent portions. Also, state in a footnote the method used to report storage (i.e. , fixed asset method or inventory method).

Line No.	Description (a)	(Acct 117.1) (b)	(Acct 117.2) (c)	Noncurrent (Acct 117.3) (d)	(Acct 117.4) (e)	Current (Acct 164.1) (f)	LNG (Acct 164.2) (g)	LNG (Acct 164.3) (h)	Total (i)
1	Balance at beginning of year (as adjusted)					$ 3,681,969	$ 3,166,527		$ 6,848,496
2	Gas delivered to storage (contra acct.)					0	0		0
3	Gas withdrawn from storage (contra acct.)					0	0		0
4	Other debits or credits (net)					(3,681,969)	0		(3,681,969)
5	Balance end of year					$ -	$ 3,166,527		$ 3,166,527
6	Dth					0	562,200		562,200
7	Amount per Dth					$ -	$ 5.6324		$ 5.6324

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report **Dec. 31, 2012**

INVESTMENTS (Account 123, 124, and 136)

1. Report below investments in Accounts 123, Investments in Associated Companies, 124, Other Investments, and 136, Temporary Cash Investments.

2. Provide a subheading for each account and list thereunder the information called for:

(a) Investment in Securities-List and describe each security owned, giving name of issuer, date acquired and date of maturity. For bonds, also give principal amount, date of issue, maturity, and interest rate. For capital stock (including capital stock of respondent reaquired under a definite plan for resale pursuant to authorization by the Board of Directors, and included in Account 124, Other Investments) state number of shares, class, and series of stock. Minor investments may be grouped by classes. Investments included in Account 136, Temporary Cash Investments, also may be grouped by classes.

(b) Investments Advances-Report separately for each person or company the amounts of loans or investment advances that are properly includable in Account 123. Include advances subject to current repayment in Account 145 and 146. With respect to each advance, show whether the advance is a note or open account.

Line No.	Description of Investment (a)	* (b)	Book Cost at Beginning of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain (c)	Purchases or Additions During the Year (d)
1				
2	Account 124			
3	Oregon weatherization loans		-	-
4	Customer Note Receivable		-	-
5	SERP Plan Assets		9,479,236	-
6	SISP Plan Assets		-	17,548
7				
8				
9				
10				
11	Account 136			
12	Short-term deposits of cash in interest			
13	bearing accounts (cash management accts)		-	-
14				
15	Short-term deposits of cash in interest			
16	bearing accounts (Exec Deferred Compensation)		-	-
17				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec. 31, 2012

INVESTMENTS (Account 123, 124, and 136) (continued)

List each note, giving date of issuance, maturity date, and specifying whether note is a renewal. Designate any advances due from officers, directors, stockholders, or employees.
3. Designate with an asterisk in column (b) any securities, notes or accounts that were pledged, and in a footnoe state the name of pledges and purpose of the pledge.
4. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and cite Commission, date of authorization, and case or docket number.
5. Report in column (h) interest and dividend revenues from investments including such revenues from securities disposed of during the year.
6. In column (i) report for each investment disposed of during the year the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including any dividend or interest adjustment includible in column (h).

Line No.	Sales or Other Dispositions During Year (e)	Principal Amount or No. of Shares at End of Year (f)	Book Cost at End of Year (If book cost is different from cost to respondent, give cost to respondent in a footnoe and explain difference) (g)	Revenues for Year (h)	Gain or Loss from Investment Disposed of (i)
1					
2					
3	-		-	-	-
4	-		-	-	-
5	(578,978)		9,722,357	822,099	-
6	-		17,548	-	-
7					
8					
9					
10					
11					
12					
13	-		-	-	-
14					
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16	-		-	-	-
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec. 31, 2012**

INVESTMENTS IN SUBSIDIARY COMPANIES (Accounts 123.1)

1. Report below investments in Account 123.1, Investments in Subsidiary Companies.
2. Provide a subheading for each company and list thereunder the information called for below. Sub-total by company and give a total in columns (e), (f), (g) and (h).
(a) Investment in Securities-List and describe each security owned. For bonds give also principal amount, date of issue, maturity, and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The total in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2				
3				
4				
5				
6	**CGC Resources books were dissolved 12/31/08, but the company**			
7	**continues for gas supply contracting purposes only**			
8				
9				
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40	**TOTAL Cost of Account 123.1 $**		**TOTAL**	-

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec. 31, 2012

INVESTMENTS IN SUBSIDIARY COMPANIES (Accounts 123.1) (continued)

4. Designate in a footnote, any securities, notes, or accounts that were pledged, and state the name of pledges and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report in column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost), and the selling price thereof, not including interest adjustments includible in column (f).
8. Report on Line 40, column (a) the total cost of Account 123.1.

Line No.	Equity in Subsidiary Earnings for Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1				
2	-			
3				
4				
5	-			
6				
7	-			
8				
9	-			
10				
11				
12				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec. 31, 2012

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant & Regulatory Study Costs (Acct 182.2)

1. Report below the particulars (details) on each prepayment.

Line No.	Nature of Payments (a)	Balance at End of Year (in dollars) (b)
1	Prepaid Insurance	121,532
2	Prepaid Rents	3,798,141
3	Prepaid Taxes	667,641
3a	Prepaid Pension	-
3b	Prepaid Executive Supplemental Retirement	-
4	Prepaid Interest	-
5	Miscellaneous Prepayments	31,579
6	**TOTAL -**	**4,618,893**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec. 31, 2012**

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant & Regulatory Study Costs (Acct 182.2)

(Continued)

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss (Include the date of loss, the date of Commission authorization to use Account 182.1 and period of amortization [mo, yr to mo. yr]). Add rows as necessary to report all data. (a)	Balance at Beginning of Year (b)	Total Amount of Loss (c)	Losses Recognized During Year (d)	Written off During Year Account Charged (e)	Written off During Year Amount (f)	Balance at End of Year (g)
7							
8							
9	none						
10							
11							
12							
13							
14							
15	**TOTAL -**						

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant & Regulatory Study Costs (Acct 182.2) (Continued)

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (Account 182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the drscription of costs, the date of Commission authorization to use Account 182.2 and period of amortization (mo, yr, to mo, yr). Add rows as necessary to report all data. Number rows in sequence beginning with the next row number after the last row number used in extraordinary property losses. (a)	Balance at Beginning of Year (b)	Total Amount of Loss (c)	Costs Recognized During Year (d)	Written off During Year Account Charged (e)	Written off During Year Amount (f)	Balance at End of Year (g)
16							
17							
18	none						
19							
20							
21							
22							
23							
24							
25							
26	**Total**						

Name of Respondent **Cascade Natural Gas Corporation**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report **Dec. 31, 2012**

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the details called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other accounts).
2. For regulatory assets being amortized, show period of amortization in column (a).
3. Minor items (5% of the balance at End of Year for Account 182.3 or amounts less than $250,000, whichever is less) may be grouped by classes.
4. Report separately any "Deferred Regulatory Commission Expenses" that are also reported on pages 350-351, Regulatory Commission Expenses.
5. Provide in a footnote, for each line item, the regulatory ciation where authoriztion for the regulatory asset has been granted (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning Current Year (b)	Debits (c)	Written off During Quarter/Year Account (d)	Written off During Period Amount Recovered (e)	Written off During Period Amount Deemed Unrecoverable (f)	Balance at End of Current Quarter/Year (g)
1							
2							
3							
4	Miscellaneous	-					-
5							
6							
7	OR Tax Rate Change	(449,827)	23,675	various		-	(426,152)
8							
9	Asset Retirement Obligation	419,258	53,831		-	-	473,089
10	(WA regulatory asset)						
11							
12	Asset Retirement Obligation	41,171	2,619		-	-	43,790
13	(OR regulatory asset)						
14							
15	SFAS 109 Regulatory Asset	(449,294)	882,205	various		-	432,911
16	(OR regulatory asset)						
17							
18	FAS 158 Regulatory Asset	55,260,783	116,484		-	-	55,377,267
19	Total system asset						
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40	**Total system asset**	**54,822,091**	**1,078,814**		**-**	**-**	**55,900,905**

Name of Respondent **Cascade Natural Gas Corporation**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report End of **Dec. 31, 2012**

MISCELLANEOUS DEFERRED DEBITS (Account 186)

1. Report below the details called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a).
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	Credits Account Charged (d)	Credits Amount (e)	Balance at End of Year (f)
1	WA Conservation Programs	4,247,659	6,655,569	4800-4813	6,995,633	3,907,595
2	(amortization period 11/10-present)					
3						
4	WA Bremerton Manufactured Gas Plant Remediation	6,364,769	7,633,813		21,612	13,976,970
5						
6	WA Gas Management Sharing Margin	218,463	7,161	4800-4813, 4890	46,225	179,399
7	(amortization period 11/10-present)					
8						
9	WA Over-refunded Temporary Revenue Credit	59,727	14,628		10,625	63,730
10						
11	WA Core Gas Supply Hedging (current & noncurrent)	392,681	701,325		1,094,006	-
12	**Subtotal WA**	**11,283,299**	**15,012,496**		**8,168,101**	**18,127,694**
13						
14						
15	OR Conservation Programs	355,828	2,644,120	4800-4813, 4890	3,008,090	(8,142)
16	(amortization period 11/10-present)					
17						
18	OR Eugene Manufactured Gas Plant Remediation	1,240,000	166,728		9,675	1,397,053
19						
20	OR Intervenor Funding	24,616	41,794	4800-4813, 4890	30,625	35,785
21	(amortization period 11/10-present)					
22						
23	OR Over-refunded Temporary Revenue Credit	3,030	312		-	3,342
24						
25	OR Core Gas Supply Hedging (current & noncurrent)	43,954	68,560		112,514	-
26	**Subtotal OR**	**1,667,428**	**2,921,514**		**3,160,904**	**1,428,038**
27						
28						
29	I/C Asset - Net Benefit Funds	1,617,016	-		-	1,617,016
30						
31						
32						
33						
34						
35						
36						
37						-
38						
39	Miscellaneous work in progress					
40	TOTAL -	14,567,743	17,934,010		11,329,005	21,172,748

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[Next page is 234]

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

Accumulated Deferred Income Taxes (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.
3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be include in the development of jurisdictional recourse rates.

Line No	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)
1	Account 190			
2	Electric	-		
3	Gas	24,456,261	2,721,781	-
4		-		
5	Total (Total of Lines 2 thru 4)	24,456,261	2,721,781	-
6		-		
7	TOTAL Account 190 (Lines 5 thru 6)	24,456,261	2,721,781	-
8	Classification of TOTAL			
9	Federal Income Tax	23,784,568	2,530,712	-
10	State Income Tax	671,693	191,069	-
11	Local Income Tax	-	-	-
	Amounts assigned to jurisdictions as follows:			
	Federal Income Tax - Washington	NA	1,887,152	-
	Federal Income Tax - Oregon	NA	643,560	-
	State Income Tax - Oregon	NA	191,069	-

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

Accumulated Deferred Income Taxes (Account 190) (continued)

Line No	Changes during Year Amounts Debited to Account 410.2 (e)	Changes during Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (I)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2							
3	-	-	Regulatory accounts related to FAS 158 and OR rate change adjustments	660,206			27,838,248
4							
5	-	-		660,206		-	27,838,248
6							
7	-	-		660,206		-	27,838,248
8							
9	-	-		347,184			26,662,464
10	-	-		313,022			1,175,784
11	-	-		-		-	-
	-	-		258,895		-	NA
	-	-		88,289		-	NA
	-	-		313,022		-	NA

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

CAPITAL STOCK (Account 201 and 204)

1. Report below the details called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized b Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common stock - not publicly traded	1,000	1.00	
3				
4				
5				
6				
7				
8				
9				
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Capital Stock (Account 201 and 204)

4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Outstanding per Bal. Sheet (total amt outstanding without reduction for amts held by respondent) Shares (e)	Outstanding per Bal. Sheet Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (I)	Held by Respondent In Sinking and Other Funds Cost (j)
1						
2	1,000	$ 1,000				
3						
4						
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Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

Capital Stock: Subscribed, Liability for Conversion, Premium on, and Installments Recieved on (Accts 202, 203, 205, 206, 207, and 212)

1. Show for each of the above accounts the amounts applying to each class and series of capital stock.
2. For Account 202, Common Stock Subscribed, and Account 205, Preferred Stock Subscribed, show the subscription price and the balance due on each class at the end of year.
3. Describe in a footnote the agreement and transactions under which a conversion liability existed under Account 203, Common Stock Liability for Conversion, or Account 206, Preferred Stock Liability for Conversion, at the end of year.
4. For Premium on Account 207, Capital Stock, designate with an asterisk in column (b), any amounts representing the excess of consideration received over stated values of stocks without par value.

Line No.	Name of Account and Description of Item (a)	* (b)	Number of Shares (c)	Amount (d)
1	Account 207			
2				
3	Premium on Capital Stock - Common		1,000	$ 117,703,952
4				
5	Represents excess received over $1.00 par value			
6	of common stock			
7				
8				
9				
10				
11				
12				
13				
14				
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39				
40	TOTAL		1,000	$ 117,703,952

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

Other Paid-In Capital (Accounts 208-211)

1. Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as a total of all accounts for reconciliation with balance sheet, page 112. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.

(b) Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210):	
2	Miscellaneous Paid-In Capital (Account 211):	
3		
4	Balance at beginning of year	$ -
5		$ -
6		
7		
8	Balance at end of year	$ -
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40	**Total**	

Name of Respondent	This Report Is:	Date of Report	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

DISCOUNT ON CAPITAL STOCK (ACCOUNT 213)

1. Report the balance at end of year of discount on capital stock for each class and series of capital stock. Use as many rows as necessary to report all data.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving details of the change. State the reason for any charge-off during the year and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	NONE	
2		
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	TOTAL	

CAPITAL STOCK EXPENSE (ACCOUNT 214)

1. Report the balance at end of year of capital stock expenses for each class and series of capital stock. Use as many rows as necessary to report all data. Number the rows in sequence starting from the last row number used for Discount on Capital Stock above.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving details of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
16	NONE	
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
	TOTAL	

Securities issued or Assumed and Securities Refunded or Retired During the Year

1. Furnish a supplemental statement briefly describing security financing and refinancing transactions during the year and the accounting for the securities, discounts, premiums, expenses, and related gains or losses. Identify as to Commission authorization numbers and dates.
2. Provide details showing the full accounting for the total principal amount, par value, or stated value of each class and series of security issued, assumed, retired, or refunded and the accounting for premiums, discounts, expenses, and gains or losses relating to the securities. Set forth the facts of the accounting clearly with regard to redemption premiums, unamortized discounts, expenses, and gain or losses relating to securities retired or refunded, including the accounting for such amounts carried in the respondent's accounts at the date of the refunding or refinancing transactions with respect to securities previously refunded or retired.

3. Include in the identification of each class and series of security, as appropriate, the interest or dividend rate, nominal date of issuance, maturity date, aggregate principal amount, par value or stated value, and number of shares. Give also the issuance of redemption price and name of the principal underwriting firm through which the security transactions were consummated.
4. Where the accounting for amounts relating to securities refunded or retired is other than that specified in General Instruction 17 of the Uniform System of Accounts, cite the Commission authorization for the different accounting and state the accounting method.
5. For securities assumed, give the name of the company for which the liability on the securities was assumed as well as details of the transactions whereby the respondent undertook to pay obligations of another company. If any unamortized discount, premiums, expenses, and gains or losses were taken over onto the respondent's books, furnish details of these amounts with amounts relating to refunded securities clearly earmarked.

None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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LONG TERM DEBT (Accounts 221, 222, 223, and 224)

1. Report by Balance Sheet Account the details concerning long-term debt included in Account 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.

Line No.	Class and Series of Obligation and Name of Stock Exchange (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (d)
1	Account 224			
2				
3	Other Long Term Debt:			
4				
5				
6	Medium Term Notes	2-93	2-13	4,000,000
7	Medium Term Notes	2-93	2-13	10,000,000
8	Medium Term Notes	2-93	2-13	10,000,000
9	Medium Term Notes	9-97	9-27	20,000,000
10	Medium Term Notes	3-99	3-29	15,000,000
11	Insured Quarterly. Notes	2-05	2-35	25,090,000
12	Notes	09-05	9-20	15,000,000
13	Senior Notes	03-07	03-37	40,000,000
14				
15				
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40	**TOTAL**			**139,090,000**

Name of Respondent **Cascade Natural Gas Corporation**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of Report **Dec. 31, 2012**

LONG TERM DEBT (Accounts 221, 222, 223, and 224) (continued)

5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (f). Explain in a footnote any difference between the total of column (f) and the total Account 427, Interest on Long-Term Debt and Account 430, interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Interest for Year Rate (in %) (e)	Interest for Year Amount (f)	Held by Respondent Reacquired Bond (Acct 222) (g)	Held by Respondent Sinking and Other Funds (h)	Redemption Price per $100 at End of Year (i)
1	8.06%	1,043,770			Non-Redeemable
2	8.10%	412,875			Non-Redeemable
3	8.11%	248,031			Non-Redeemable
4	7.95%	318,000			Non-Redeemable
5	8.01%	801,000			Non-Redeemable
6	7.95%	795,000			Non-Redeemable
7	7.48%	1,496,000			Non-Redeemable
8	7.10%	1,064,700			Non-Redeemable
9	5.25%	1,325,638			Non-Redeemable
10	5.21%	781,500			Non-Redeemable
11	5.79%	2,316,000			Non-Redeemable
12					
13					
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40		**10,602,514**			

Name of Respondent	This Report Is:	Date of Report	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

UNAMORTIZED DEBT EXPENSE, PREMIUM AND DISCOUNT ON LONG-TERM DEBT (ACCOUNTS 181, 225, 226)

1. Report under separate subheadings for Unamortized Debt Expense, Unamortized Premium on Long-Term Debt and Unamortized Discount on Long-Term Debt, details of expense, premium or discount applicable to each class and series of long-term debt.
2. Show premium amounts by enclosing the figures in parentheses.
3. In column (b) show the principal amount of bonds or other long-term debt originally issued.
4. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.

Line No.	Designation of Long-Term Debt (a)	Principal Amount of Debt Issued (b)	Total Expense Premium or Discount (c)	Amortization Period Date From (d)	Amortization Period Date To (e)
1	Unamortized Debt Expense (Account 181)				
2					
3	Medium Term Notes 8.06%	14,000,000	140,846	9-92	9-12
4	Medium Term Notes 8.10%	5,000,000	50,302	10-92	10-12
5	Medium Term Notes 8.11%	3,000,000	30,181	10-92	10-12
6	Medium Term Notes 7.95%	4,000,000	40,242	2-93	2-13
7	Medium Term Notes 8.01%	10,000,000	100,604	2-93	2-13
8	Medium Term Notes 7.95%	10,000,000	100,604	2-93	2-13
9	Medium Term Notes 7.48%	20,000,000	201,406	9-97	9-27
10	Medium Term Notes 7.10%	15,000,000	151,056	3-99	3-29
11	Insured Quarterly Notes 5.25%	25,090,000	1,947,598	2-05	02-35
12	Notes 5.21%	15,000,000	238,755	09-05	9-20
13	Senior Notes 5.79%	40,000,000	232,781	03-07	03-37
14	Revolving Credit Agreement	-	58,847	10-04	12-13
15					
16					
17					
18					
19	**Totals**				
20					
21					
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25					

Name of Respondent **Cascade Natural Gas Corporation**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year Ending **Dec. 31, 2012**

UNAMORTIZED DEBT EXPENSE, PREMIUM AND DISCOUNT ON LONG-TERM DEBT (Accts 181, 225, 226) (cont.)

5. Furnish in a footnote details regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.
6. Identify separately undisposed amounts applicable to issues which were redeemed in prior years.
7. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt-Credit.

Line No.	Balance at Beginning of Year (f)	Debits During Year (g)	Credits During Year (h)	Balance at End of Year (i)
1	4,752	-	4,752	-
2	1,930	-	1,930	-
3	1,158	-	1,158	-
4	2,199	-	2,012	187
5	5,563	-	5,033	530
6	5,741	-	5,033	708
7	105,456	-	6,714	98,742
8	86,437	-	5,035	81,402
9	1,549,586	-	65,014	1,484,572
10	89,696	-	16,177	73,519
11	195,595	-	7,770	187,825
12	-	-	-	-
13				
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19	2,048,113	-	120,628	1,927,485
20				
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24				
25				

Name of Respondent	This Report Is:	Date of Report	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec 31, 2012**

UNAMORTIZED LOSS AND GAIN ON REACQUIRED DEBT (ACCOUNTS 189, 257)

1. Report under separate subheadings for Unamortized Loss and Unamortized Gain on Reacquired Debt, details of gain and loss, including maturity date, on reacquisition applicable to each class and series of long-term debt. If gain or loss resulted from a refunding transactions, include also the maturity date of the new issue.
2. In column (c) show the principal amount of bonds or other long-term debt reacquired.
3. In column (d) show the net gain or net loss realized on each debt reacquisition as computed in accordance with General Instruction 17 of the Uniform Systems of Accounts.
4. Show loss amounts by enclosing the figures in parentheses.
5. Explain in a footnote any debits and credits other than amortization debited to Account 428.1, Amortization of Loss on Reacquired Debt, or credited to Account 429.1, Amortization of Gain on Reacquired Debt-Credit.

Line No.	Designation of Long-Term Debt (a)	Date Reacquired (b)	Principal of Debt Reacquired (c)	Net Gain or Loss (d)	Balance at Beginning of Year (e)	Balance at End of Year (f)
1	Unamortized Loss on					
2	Reacquired Debt (Acct 189)					
3						
4						
5	10.1/8% Senior Notes					
6	Due 10/02/2007 (1)	9/30/1992	12,378,000	(1,214,817)	41,225	-
7						
8						
9	9.875% Debentures					
10	Due 8/01/2013 (2)	3/1/1993	21,677,000	(1,984,012)	193,677	26,819
11						
12						
13	7.50% Notes					
14	Due 11/15/2031 (3)	11/15/2001	39,729,000	(1,229,120)	1,031,095	990,124
15						
16			**73,784,000**	**(4,427,949)**	**1,265,997**	**1,016,943**
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The loss associated with each reacquisition consists of a reacquisition premium, other reacquisition expenses, and remaining unamortized issuance costs (Account 181) at the time of reacquisition.

(1) Refunded by 8.06% Medium Term Notes for $14,000,000 due 9/04/2012.
(2) Refunded by Medium Term Notes ranging from 7.95% to 8.01% totaling $24,000,000 due 2/2013.
(3) 7.5% Notes were reacquired in March 2007 and refunded by 5.79% Senior Notes for $40,000,000 due 3/08/2037.
The remaining unamortized debt expense of $1,229,120 was reclassified to unamortized loss on reacquired debt.

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[Next page is 261]

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal Income Tax accruals and show computation of such tax accrual. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year.
2. If the utility is a member of a group that files consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignments, or sharing of the consolidated tax among the group members.

Line No.	Details (a)	Amount (b)
1	Net Income for the Year (Page 116)	13,384,050
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	CIAC	1,423,741
6	Customer Advances - 2520.000 to 2520.2991	20,902
7	263A Adjustment - UNICAP	13,158
8	Tax Gain (loss) on disposal of assets:	
9	Pre-1981 assets	1,424,333
10	Post-1980 assets	(228,628)
11	Installment sale - Seattle GO	1,285,184
12	TOTAL	3,938,690
13	Deductions Recorded on Books Not Deducted for Return	
14	Tax Expense	7,460,124
15	Vacation Accrual - current year	1,399,250
16	Retiree Medical Accrual	343,514
17	Amort of loss on reacquired debt (4281)	249,054
18	SFAS No.87 pension plan accrual	1,595,543
19	SFAS No.87 accrual-SERP DO add back bk expense	788,262
20	STIP accrual - addback	331,035
21	Bad Debt Expense	2,480,745
22	Charitable Contributions (5981.4261)	203,715
23	Broken Meter interest charges	7,249
24	Depreciation provision	
25	Pre-1981	362,279
26	Post-1980	19,871,922
27	Permanent diff's	
28	50 % of business meals & entertainment	170,258
29	Penalties (5984)	2,187
30	Lobbying (5912.4264)	110,582
31	Interest Expense	42,336
32	TOTAL	35,418,055
33	Income Recorded on Books Not Included in Return	
34	AFUDC Equity	(464,259)
35	Interest capitalized adj (IRS>books)	(107,373)
36	TOTAL	(571,632)
37	Adjusted Net Income to carry forward to page 261A, line 1	52,169,163

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec. 31, 2012**

TAXABLE INCOME FOR FEDERAL INCOME TAXES (cont.)

1	Adjusted Net Income carried forward from page 261, line 37			52,169,163
2	Deductions on Return Not Charged Against Book Income			
3	Vacation accrual - prior year			(1,463,976)
4	Depreciation & amortization of plant			
5	Pre-1981			(414,553)
6	Post-1980			(42,253,335)
7	CC&B Deduction			(2,495,149)
8	401K Dividends (MDUR)			(140,578)
9	Funding of pension plan			(854,073)
10	SERP-perm difference piece			(807,276)
11	SERP - benefit pymts out of plan			(578,978)
12	Retiree Medical payments			(372,320)
13	Severance accrual - prior year			-
14	STIP accrual - prior year			(458,084)
15	Deferred Gas Costs			-
16	Bad debts written off			(2,344,728)
17	Royalty Income (15% of royalty income receipts)			(2,246)
18	Bremerton MGP expenses deferred			(148,407)
19	Eugene MGP expenses deferred			(97,054)
20	Oregon State Income Tax			28,425
21	TOTAL			(52,402,332)
22	Federal Tax Net Income			**(233,169)**
23	Show Computation of Tax:			
24	Rate			35%
25	Estimated Tax Return Federal Income Tax			**(81,610)**
26	Adjustments:			
27	Difference between 12/31/11 accrual and tax return			(1,133,371)
28	Audit adjustment			(35,649)
29	Provision for Current Federal Income Tax			**(1,250,630)**
30				
31	Allocated to:	409.1	409.2	Total
32	Washington	(934,523)	1,952	(932,571)
33	Oregon	(318,693)	634	(318,059)
34	Total	**(1,253,216)**	**2,586**	**(1,250,630)**
35				
36	OREGON STATE TAX CALCULATION:			
37	Taxable Income for Federal Tax			(233,169)
38	Oregon adjustments to Federal Taxable Income			
39	Oregon State Income Tax Expense deducted from Federal Return			(28,425)
40	Bonus Depreciation Adjustment			(1,609,622)
41	Post-80 gain adjustment			1,170
42	Taxable Income for Oregon Tax			(1,870,046)
43	Oregon Apportionment Factor			20.0000%
44	Oregon Taxable Income			(374,009)
45	Oregon Tax Rate			7.60%
46	Estimated Tax Return Oregon Income Tax			(28,425)
47	Adjustments:			
48	Difference between 12/31/11 accrual and tax return			(57,514)
49	Audit adjustment			(996)
50	Provision for Current Oregon Income Tax			**(86,935)**
51				
52	Allocated to:	409.1	409.2	Total
53	Total	**(87,115)**	**180**	**(86,935)**

Name of Respondent	This Report is:	Date of Report	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec 31, 2012**

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)

1. Give details of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged directly to final accounts (not charged to prepaid or accrued taxes). Enter the amount in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to the portion of prepaid taxes charged to current year, and (c) taxes paid and charged directly to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)		Balance at Beg. of Year Taxes Accrued (b)	Balance at Beg. of Year Prepaid Taxes (c)
1	Income Tax	-Oregon Accrued	112,931	-
2		-Federal Accrued	1,668,044	-
3		-Fin 48 - current	-	-
4	Gross Revenue	-Washington	503,962	
5		-Oregon	-	0
6	Dept of Energy	-Oregon		33,065
7	City Franchise & Occupation	-Washington	1,692,329	
8		-Oregon	766,452	
9	Property	-Washington	2,802,966	
10		-Oregon	-	610,197
11	Payroll Taxes		51,366	
12	State Excise	-Washington	1,998,609	
13				
14	Miscellaneous			
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	TOTAL		9,596,659	643,262

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year Ending **Dec 31, 2012**

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged)

during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.

2. Include on this page, taxes paid during the year and charged directly to final accounts (not charged to prepaid or accrued taxes). Enter the amount in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.

3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to the portion of prepaid taxes charged to current year, and (c) taxes paid and charged directly to operations or accounts other than accrued and prepaid tax accounts.

4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Line No.	Gas (WA) Account 408.1, 409.1 (i)	Gas (OR) Account 408.1, 409.1 (J)	Gas (General / Interstate) (Account 408.1, 409.1) (k)	Other Income and Deductions (Account 408.2, 409.2) (l)
1		(87,115)	-	180
2	(934,523)	(318,693)	-	2,586
3				
4	406,948			
5		201,516		
6		61,277		
7	8,810,200			
8		2,627,136		
9	3,134,131		346,574	3,638
10		1,247,499		
11	781,780	252,645	750,468	
12	8,101,293			
13				
14	59,141	19,715	743	-
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Total	20,358,970	4,003,980	1,097,785	6,404

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year Ending **Dec 31, 2012**

Taxes Accrued, Prepaid and Charged During Year, Distribution of Taxes Charged (Show utility dept where applicable and acct charged) (continued)

5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Show in columns (i) thru (p) how the tax accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.
10. Items under $250,000 may be grouped.
11. Report in column (q) the applicable effective state income tax rate.

Line No.	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)	Balance at End of Year Taxes Accrued (Account 236) (g)	Balance at End of Year Prepaid Taxes (Included in Acct 165) (h)
1	(86,935)	109,877	-	(83,881)	-
2	(1,250,630)	1,270,538	-	(853,124)	-
3	-	-	1,355,760	1,355,760	
4	406,948	483,935		426,975	
5	201,516	201,516		-	-
6	61,277	56,424		-	28,212
7	8,810,200	9,221,826		1,280,703	
8	2,627,136	2,790,274		603,314	
9	3,484,343	3,095,356		3,191,953	
10	1,247,499	1,276,731		-	639,429
11	1,784,893	1,788,331		47,928	
12	8,101,293	8,488,516		1,611,386	
13					
14	79,599	79,599			
15					
16					
17					
18					
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31					
	25,467,139	28,862,923	1,355,760	7,581,014	667,641

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year Ending **Dec 31, 2012**

5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Show in columns (i) thru (p) how the tax accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.
10. Items under $250,000 may be grouped.
11. Report in column (q) the applicable effective state income tax rate.

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Line No.	Extraordinary Items (Account 409.3) (m)	Other Utility Opn. Income (Account 408.1, 409.1) (n)	Adjustment to Ret. Earnings (Account 439) (o)	Other (p)	State/Local Income Tax Rate (q)
1					0.31%
2					
3					
4					
5					
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29					
30					
31					
Total					

Name of Respondent Cascade Natural Gas Corporation	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report Dec. 31, 2012

MISCELLANOUS CURRENT AND ACCRUED LIABILITIES (Account 242)

1. Describe and report the amount of other current and accrued liabilities at the end of year.
2. Minor items (less than $250,000) may be grouped under appropriate title.

Line No.	Item (a)	Balance at End of Year (b)
1	Accounts Payable Accrual	1,277,914
2	Accrued Paid Time Off Liability	1,506,664
3	Washington Low Income Assist Liability	783,622
4	Wages Payable	694,695
5	SERP Defined Contributions	564,647
6	Oregon Weatherization Liability	444,256
7	Energy Trust of Oregon Liability	358,374
8	Accrued 401K Defined Contributions	313,156
9	Pipeline Imbalance Accrual	287,585
10	Professional Services (bank, accounting, legal)	199,555
11	Other Misc Current Liabilities (aggregate)	179,166
12		
13		
14		
15		
16		
17		
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36		
37	**Total**	**6,609,634**

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission		**Dec. 31, 2012**

OTHER DEFERRED CREDITS (ACCOUNT 253)

1. Report below the details called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	Debit Contra Account (c)	Debit Amount (d)	Credits (e)	Balance at End of Year (f)
1	WA Deferred Gas Costs	(19,229,285)	805.1	58,717,408	(53,366,280)	(13,878,157)
2	(amortization period 11/11-present)					
3						
4	**Subtotal WA**	**(19,229,285)**		**58,717,408**	**(53,366,280)**	**(13,878,157)**
5						
6	OR Deferred Gas Costs	(989,557)	805.1	13,016,065	(17,972,807)	(5,946,299)
7	(amortization period 11/11-present)					
8						
9	OR Gross Revenue Fee Liability	1,242	4800-4813, 4890	21	(1,263)	-
10	(amortization period 11/11-present)					
11						
12	OR Earning Sharing Liability	0	805.1	59,266	(397,444)	(338,178)
13	(amortization period 11/11-present)					
14	**SubTotal OR**	**(988,315)**		**13,075,352**	**(18,371,514)**	**(6,284,477)**
15						
16	Newood Escrow Deposit	(350,000)	134 / 228.4	350,000	0	-
17	SGL Deposit	(211,040)	134 / 228.4	17,960	0	(193,080)
18	Customer Unclaimed Credits	(1,516)	131	45,944	(47,041)	(2,613)
19						
20	**Subtotal Unallocated**	**(562,556)**		**413,904**	**(47,041)**	**(195,693)**
21						
22						
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41						
42						
43						
44						
45	**TOTAL**	(20,780,156)		72,206,664	(71,784,835)	(20,358,327)

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

ACCUMULATED DEFERRED INCOME TAXES-Other Property (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.

2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	0		
3	Gas	(70,046,021)	(7,684,666)	
4		-		
5	Total (Enter Total of Lines 2 thru 4)	(70,046,021)	(7,684,666)	-
6		-		
7	TOTAL Account 282 (Enter Total of Lines 5 thru 6)	(70,046,021)	(7,684,666)	-
8	Classification of Totals			
9	Federal Income Tax	(69,082,554)	(6,902,975)	-
10	State Income Tax	(963,467)	(781,691)	-
11	Local Income Tax	-	-	-
		NA	(5,147,549)	-
		NA	(1,755,426)	-
		(963,467)	(781,691)	-

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report **Dec. 31, 2012**

ACCUMULATED DEFERRED INCOME TAXES-Other Property (Account 282) (continued)

3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Changes during Year Amounts Debited to Account 410.2 (e)	Changes during Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (I)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2							-
3	-	-	254	861,618	182.3	(927,979)	(77,797,048)
4							-
5	-	-		861,618		(927,979)	(77,797,048)
6							-
7	-	-		861,618		(927,979)	(77,797,048)
8							
9	-	-	254	861,618	182.3	-	(75,123,911)
10	-	-	254	-	182.3	(927,979)	(2,673,137)
11	-	-		-		-	-
	-	-		642,509		-	NA
	-	-		219,109		-	NA
	-	-		-		(927,979)	(2,673,137)

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

ACCUMULATED DEFERRED INCOME TAXES-Other (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric	0		
3	Gas	(27,479,312)	(3,853,071)	-
4		-		
5	Total (Total of Lines 2 thru 4)	(27,479,312)	(3,853,071)	-
6				
7	Total (Account 283) Lines 5 thru 6	(27,479,312)	(3,853,071)	-
8	Classification of TOTAL			
9	Federal Income Tax	(26,307,341)	(3,574,506)	-
10	State Income Tax	(1,171,971)	(278,565)	-
11	Local Income Tax	-	-	-
		NA	(2,665,509)	-
		NA	(908,997)	-
		(1,171,971)	(278,565)	-

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☑ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report **Dec. 31, 2012**

ACCUMULATED DEFERRED INCOME TAXES-Other (Account 283) (continued)

3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Changes during Year Amounts Debited to Account 410.2 (e)	Changes during Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2							-
3	-	-	Regulatory accounts related to deferred tax effect of OR State Tax Rate Increase	15,500	Regulatory accounts related to FAS 158 adjustment	(659,869)	(31,976,752)
4							-
5	-	-		15,500		(659,869)	(31,976,752)
6							-
7	-	-		15,500		(659,869)	(31,976,752)
8							
9	-	-		(6,299)		(347,147)	(30,235,293)
10	-	-		21,799		(312,722)	(1,741,459)
11	-	-		-		-	-
	-	-		(4,697)		(258,868)	NA
	-	-		(1,602)		(88,279)	NA
	-	-		21,799		(312,722)	(1,741,459)

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report **Dec. 31, 2012**

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the details called for concerning other regulatory liabilities which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).
2. For regulatory liabilities being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $250,000, whichever is less) may be grouped by classes.
4. Provide in a footnote, for each line item , the regulatory citation where the respondent was directed to refund the regulatory liability (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	Written off during Quarter/Period Account Credited (c)	Written off During Period Amount Deemed Refunded (d)	Written off During Period Amount Deemed Non-Refundable (e)	Credits (f)	Balance at End of Current Quarter/Year (g)
1							
2	SFAS 109 Regulatory Liab.	$ 3,433,335	282	2,002,125		2,854,183	$ 4,285,393
3							
4	Oregon Tax Rate Change	$ (62,630)	282			3,297	$ (59,333)
5							
6	11/11/11 Consol Other Tech Adj.	$ 41,640	481	41,966		326	$ -
7							
8	11/1/12 Consol Other Tech Adj.	$ -	186	24		781	$ 757
9							
10	11/12 Under-Ref Temp Rev Credit	$ -	186			3,689	$ 3,689
11							
12							
13							
14							
15							
16							
17							
18							
19							
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41							
42							
43							
44							
45	**Total**	**$ 3,412,345**		**$ 2,044,115**	**$ -**	**$ 2,862,276**	**$ 4,230,506**

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec. 31, 2012**

GAS OPERATING REVENUES

1. Report below natural gas operating revenues for each prescribed account total. The amounts must be consistent with the detailed data on succeeding pages.
2. Revenues in columns (b) and (c) include transition costs from upstream pipelines.
3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges, less revenues reflected in columns (b) through (e). Include in columns (f) and (g) revenues for Accounts 480-495.

Line No.	Title of Account (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	480 Residential Sales	none	none	none	none
2	481 Commercial and Industrial Sales				
3	482 Other Sales to Public Authorities				
4	483 Sales for Resale				
5	484 Interdepartment Sales				
6	485 Intercompany Transfers				
7	487 Forfeited Discounts				
8	488 Miscellaneous Service Revenues				
9	489.1 Revenue from Transportation of Gas of Others Through Gathering Facilities				
10	489.2 Revenue from Transportation of Gas of Others Through Transmission Facilities				
11	489.3 Revenue from Transportation of Gas of Others Through Distribution Facilities				
12	489.4 Revenue from Storing Gas of Others				
13	490 Sales of Prod. Ext. from Natual Gas				
14	491 Revenues from Natural Gas Proc. By Others				
15	492 Incidential Gasoline and Oil Sales				
16	493 Rent from Gas Property				
17	494 Interdepartment Rents				
18	495 Other Gas Revenues				
19	Subtotal:				
20	496 (Less) Provision for Rate Refunds				
21	Total -				

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec. 31, 2012

GAS OPERATING REVENUES

4. If increases or decreases from previous year are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. On Page 108, include information on major changes during the year, new service, and important rate increases or decreases.
6. Report the revenue from transportation services that are bundled with storage services as transportation service revenue.

Line No.	Other Revenues Amount for Current year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current year (h)	Total Operating Revenues Amount for Previous Year (I)	Dekatherm of Natural Gas Amount for Current year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1	$ 252,587,028	$ 298,515,263	$ 252,587,028	$ 298,515,263	28,616,848	30,450,004
2						
3						
4	$ -	$ -	$ -	$ -		
5	$ -	$ -	$ -	$ -		
6	$ -	$ -	$ -	$ -		
7	$ -	$ -	$ -	$ -		
8	$ 1,348,971	$ 1,391,767	$ 1,348,971	$ 1,391,767		
9	$ -	$ -	$ -	$ -		
10	$ -	$ -	$ -	$ -		
11	$ 22,916,355	$ 22,475,676	$ 22,916,355	$ 22,475,676	84,552,419	81,252,361
12	$ -	$ -	$ -	$ -		
13	$ -	$ -	$ -	$ -		
14	$ -	$ -	$ -	$ -		
15			$ -	$ -		
16	$ 12,600	$ 15,000	$ 12,600	$ 15,000		
17						
18	$ 123,529	$ 201,190	$ 123,529	$ 201,190		
19	$ 276,988,483	$ 322,598,896	$ 276,988,484	$ 322,598,896		
20						
21	**$ 276,988,483**	**$ 322,598,896**	**$ 276,988,484**	**$ 322,598,896**		

Name of Respondent Cascade Natural Gas Corporation	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report Dec. 31, 2012

REVENUES FROM TRANSPORTATION OF GAS OF OTHERS THROUGH GATHERING FACILITIES (Acct 489.1)

1. Report revenues and Dth of gas delivered through gathering facilities by zone of receipt (i.e. state in which gas enters respondent's system).
2. Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.

Line No.	Rate Schedule and Zone of Receipt (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	Not Applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report **Dec. 31, 2012**

REVENUES FROM TRANSPORTATION OF GAS OF OTHERS THROUGH GATHERING FACILITIES (Continued)

3. Other revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges, less revenues reflected in columns (b) through (e).
4. Delivered Dth of gas must not be adjusted for discounting.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (I)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1						
2						
3						
4						
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Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report **Dec. 31, 2012**

REVENUES FROM TRANSPORTATION OF GAS OF OTHERS THROUGH TRANSMISSION FACILITIES (Acct 489.2)

1. Report revenues and Dth of gas delivered Zone of Delivery by Rate Schedule. Total by Zone of Delivery and for all zones. If respondent does not have separate zones, porovide totals by rate schedules.
2. Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.
3. Other revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges for transportation and hub services, less revenues reflected in columns (b) through (e).

Line No.	Zone of Delivery, Rate Schedule (a)	Revenues for Transistion Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transistion Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRU and ACA Amount for Current Year (d)	Revenues for GRU and ACA Amount for Previous Year (e)
1	Not applicable				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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16					
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Name of Respondent Cascade Natural Gas Corporation	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report Dec. 31, 2012

REVENUES FROM TRANSPORTATION OF GAS OF OTHERS THROUGH TRANSMISSION FACILITIES (continued)

4. Delivered Dth of gas must not be adjusted for discounting.
5. Each incremental rate schedule and each individually certificated rate schedule must be separately reported.
6. Where transportation services are bundled with storage services, report total revenues but only transportation Dth.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (I)	Dekatherms of Natural Gas Amount for Current Year (j)	Dekatherms of Natural Gas Amount for Previous Year (k)
1						
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Name of Respondent Cascade Natural Gas Corporation	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report Dec. 31, 2012

REVENUES FROM STORING GAS OF OTHERS (Account 489.4)

1 Report revenues and Dth of gas withdrawn from storage by Rate Schedule and in total.
2 Revenues for penalties including penalties for unauthorized overruns must be reported on page 308.
3 Other revenues in columns (f) and (g) include reservation charges, deliverability charges, injection and withdrawl charges, less revenue reflected in columns (b) through (e).

Line No.		Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transition Costs and Take-or-Pay Amount for Previous Year (c)	Revenues for GRI and ACA Amount for Current Year (d)	Revenues for GRI and ACA Amount for Previous Year (e)
1	Not Applicable				
2					
3					
4					
5					
6					
7					
8					
9					
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11					
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Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report **Dec. 31, 2012**

REVENUES FROM STORING GAS OF OTHERS (continued)

4. Dth of gas withdrawn from storage must not be adjsuted for discounting.
5. Where transportation services are bundled with storage services, report only Dth withdrawn from storage.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (I)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1						
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Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

OTHER GAS REVENUES (Account 495)

Report below transactions of $250,000 or more included in Account 495, Other Gas Revenues. Group all transactions below $250,000 in one amount and provide the number of items.

Line No.	Description of Transaction (a)	Amount (in dollars) (b)
1	Commissions on Sale or Distribution of Gas of Others	
2	Compensation for Minor or Incidental Services Provided for Others	
3	Profit or Loss on Sale of Material and Supplies not Ordinarily Purchased for Resale	
4	Sales of Stream, Water, or Electicity, including Sales or Transfers to Other Departments	
5	Miscellaneous Royalties	
6	Revenues from Dehydration and Other Processing of Gas of Others except as provided for in the Instructions to Account 495	
7	Revenues for Right and/or Benefits Received from Others which are Realized Through Research, Development, and Demonstration Ventures	
8	Gains on Settlements of Imbalance Receivables and Payables	
9	Revenues from Penalties earned Pursuant to Tarriff Provisions, including Penalties Associated with Cash-out Settlements	
10	Revenues from Shipper Supplied Gas	
11	Other Revenuee (Specify):	
12	Miscellaneous Sales	$ 123,529
13		
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24		
25	TOTAL -	$ 123,529

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

Discounted Rate Services and Negotiated Rate Services

1. In column b, report the revenues from discounted rate services.
2. In column c, report the volumes of discounted rate services.
3. In column d, report the revenues from negotiated rate services.
4. In column e, report the volumes of negotiated rate services.

Line No.	Account (a)	Discounted Rate Services Revenue (b)	Discounted Rate Services Volumes (c)	Negotiated Rate Services Revenue (d)	Negotiated Rate Services Volumes (e)
1	None				
2					
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4					
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38					
39					
	TOTAL				

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year Ending
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission		**Dec. 31, 2012**

GAS OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production		
3	Manufactured Gas Production (Submit Supplemental Statement)	0	0
4	B. Natural Gas Production		
5	B1. Natural Gas Production and Gathering		
6	Operation		
7	750 Operation Supervision and Engineering		
8	751 Production Maps and Records		
9	752 Gas Wells Expenses		
10	753 Field Lines Expenses		
11	754 Field Compressor Station Expenses		
12	755 Field Compressor Station Fuel and Power		
13	756 Field Measuring and Regulating Station Expenses		
14	757 Purification Expenses		
15	758 Gas Well Royalties		
16	759 Other Expenses		
17	760 Rents		
18	Total Operation (Enter Total of lines 7 thru 17)	None	None
19	Maintenance		
20	761 Maintenance Supervision and Engineering		
21	762 Maintenance of Structures and Improvements		
22	763 Maintenance of Producing Gas Wells		
23	764 Maintenance of Field Lines		
24	765 Maintenance of Field Compressor Station Equipment		
25	766 Maintenance of Field Meas. and Reg. Sta. Equipment		
26	767 Maintenance of Purification Equipment		
27	768 Maintenance of Drilling and Cleaning Equipment		
28	769 Maintenance of Other Equipment		
29	TOTAL Maintenance (Enter Total of lines 20 thru 28)	**None**	**None**
30	TOTAL Natural Gas Production & Gathering (Total of lines 18 & 29)	**None**	**None**

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering		
34	771 Operation Labor		
35	772 Gas Shrinkage		
36	773 Fuel		
37	774 Power		
38	775 Materials		
39	776 Operation Supplies and Expenses		
40	777 Gas Processed by Others		
41	778 Royalties on Products Extracted		
42	779 Marketing Expenses		
43	780 Products Purchases for Resale		
44	781 Variation in Products Inventory		
45	(Less) 782 Extracted Products Used by the Utility - Credit		
46	783 Rents		
47	TOTAL Operation (Total of lines 33 thru 46)	**None**	**None**
48	Maintenance		
49	784 Maintenance Supervision and Engineering		
50	785 Maintenance of Structures and Improvements		
51	786 Maintenance of Extraction and Refining Equipment		
52	787 Maintenance of Pipe Lines		
53	788 Maintenance of Extracted Products Storage Equipment		
54	789 Maintenance of Compressor Equipment		
55	790 Maintenance of Gas Measuring and Regulating Equipment		
56	791 Maintenance of Other Equipment		
57	TOTAL Maintenance (Total of lines 49 thru 56)	**None**	**None**
58	TOTAL Products Extraction (Total of lines 47 and 57)	**None**	**None**

Name of Respondent	This Report is:	Date of Report	Year Ending
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals		
62	796 Nonproductive Well Drilling		
63	797 Abandoned Leases		
64	798 Other Exploration		
65	TOTAL Exploration & Development (Total of lines 61 thru 64)	**$ -**	**$ -**
66	D. Other Gas Supply Expenses		
67	Operation		
68	800 Natural Gas Well Head Purchases	$ -	$ -
69	800.1 Natural Gas Well Head Purchases, Intracompany Transfers		
70	801 Natural Gas Field Line Purchases		
71	802 Natural Gas Gasoline Plant Outlet Purchases		
72	803 Natural Gas Transmission Line Purchases		
73	804 Natural Gas City Gate Purchases	$ 157,121,712	$ 187,621,292
74	804.1 Liquefied Natural Gas Purchases	$ -	$ -
75	805 Other Gas Purchases	$ -	$ -
76	(Less) 805.1 Purchased Gas Cost Adjustments	$ (6,570,310)	$ 1,439,122
77	TOTAL Purchased Gas (Total of lines 68 to 76)	**$ 150,551,402**	**$ 189,060,414**
78	806 Exchange Gas	$ -	$ -
79	Purchased Gas Expenses		
80	807.1 Well Expenses - Purchased Gas	$ -	$ -
81	807.2 Operation of Purchased Gas Measuring Stations	$ -	$ -
82	807.3 Maintenance of Purchased Gas Measuring Stations	$ -	$ -
83	807.4 Purchased Gas Calculations Expenses	$ -	$ -
84	807.5 Other Purchased Gas Expenses	$ -	$ -
85	TOTAL Purchased Gas Expenses (Total of lines 80 thru 84)	**$ -**	**$ -**

Name of Respondent	This Report is:	Date of Report	Year Ending
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
86	808.1 Gas Withdrawn from Storage - Debit	$ 2,498,899	$ 5,871,898
87	(Less) 808.2 Gas Delivered to Storage - Credit	$ (2,923,968)	$ (5,436,305)
88	809.1 Withdrawals of Liquefied Natural Gas for Processing - Debit		
89	(Less) 809.2 Deliveries of Natural Gas for Processing - Credit		
90	Gas Used in Utility Operations - Credit		
91	810 Gas Used for Compressor Station Fuel - Credit		
92	811 Gas Used for Products Extraction - Credit		
93	812 Gas Used for Other Utility Operations - Credit	$ (76,028)	$ (86,528)
94	TOTAL Gas Used in Utility Operations - Credit (Total of lines 91 thru 93)	**$ (76,028)**	**$ (86,528)**
95	813 Other Gas Supply Expenses	$ 216,405	$ 91,688
96	TOTAL Other Gas Supply Exp (Total of lines 77, 78, 85, 86 thru 89, 94, 95)	**$ 150,266,710**	**$ 189,501,167**
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65 and 96)	**$ 150,266,710**	**$ 189,501,167**
98	2. NATURAL GAS STORAGE, TERMINALING & PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering		
102	815 Maps and Records		
103	816 Wells Expenses		
104	817 Lines Expense		
105	818 Compressor Station Expenses		
106	819 Compressor Station Fuel and Power		
107	820 Measuring and Regulating Station Expenses		
108	821 Purification Expenses		
109	822 Exploration and Development		
110	823 Gas Losses		
111	824 Other Expenses		
112	825 Storage Well Royalties		
113	826 Rents		
114	TOTAL Operation (Enter Total of lines 101 thru 113)	**None**	**None**

Name of Respondent	This Report is:	Date of Report	Year Ending
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
115	Maintenance		
116	830 Maintenance Supervision and Engineering		
117	831 Maintenance of Structures and Improvements		
118	832 Maintenance of Reservoirs and Wells		
119	833 Maintenance of Lines		
120	834 Maintenance of Compressor Station Equipment		
121	835 Maintenance of Measuring and Regulating Station Equipment		
122	836 Maintenance of Purification Equipment		
123	837 Maintenance of Other Equipment		
124	TOTAL Maintenance (Enter Total of lines 116 thru 123)		
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)	**None**	**None**
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering		
129	841 Operation Labor and Expenses		
130	842 Rents		
131	842.1 Fuel		
132	842.2 Power		
133	842.3 Gas Losses		
134	TOTAL Operation (Enter Total of lines 128 thru 133)	**None**	**None**
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering		
137	843.2 Maintenance of Structures		
138	843.3 Maintenance of Gas Holders		
139	843.4 Maintenance of Purification Equipment		
140	843.5 Maintenance of Liquefaction Equipment		
141	843.6 Maintenance of Vaporizing Equipment		
142	843.7 Maintenance of Compressor Equipment		
143	843.8 Maintenance of Measuring and Regulating Equipment		
144	843.9 Maintenance of Other Equipment		
145	TOTAL Maintenance (Enter Total of lines 136 thru 144)	**None**	**None**
146	TOTAL Other Storage Expenses (Enter Total of lines 134 and 145)	**None**	**None**

Name of Respondent	This Report is:	Date of Report	Year Ending
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering		
150	844.2 LNG Processing Terminal Labor and Expenses		
151	844.3 Liquefaction Processing Labor and Expenses		
152	844.4 Liquefaction Transportation Labor and Expenses		
153	844.5 Measuring and Regulation Labor and Expenses		
154	844.6 Compressor Station Labor and Expenses		
155	844.7 Communication System Expenses		
156	844.8 System Control and Load Dispatching		
157	845.1 Fuel		
158	845.2 Power		
159	845.3 Rents		
160	845.4 Demurrage Charges		
161	(Less) 845.5 Wharfage Receipts - Credit		
162	845.6 Processing Liquefied or Vaporized Gas by Others		
163	846.1 Gas Losses		
164	846.2 Other Expenses		
165	TOTAL Operation (Enter Total of lines 149 thru 164)	**None**	**None**
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering		
168	847.2 Maintenance of Structures and Improvements		
169	847.3 Maintenance of LNG Processing Terminal Equipment		
170	847.4 Maintenance of LNG Transportation Equipment		
171	847.5 Maintenance of Measuring and Regulating Equipment		
172	847.6 Maintenance of Compressor Station Equipment		
173	847.7 Maintenance of Communication Equipment		
174	847.8 Maintenance of Other Equipment		
175	TOTAL Maintenance (Enter Total of lines 167 thru 174)		
176	TOTAL Liquefied Nat Gas Terminaling & Proc Exp (Total of lines 165 & 175)	**None**	**None**
177	TOTAL Natural Gas Storage (Enter Total of lines 125, 146 and 176)	**None**	**None**

Name of Respondent	This Report is:	Date of Report	Year Ending
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering		
181	851 System Control and Load Dispatching		
182	852 Communication System Expenses		
183	853 Compressor Station Labor and Expenses		
184	854 Gas for Compressor Station Fuel		
185	855 Other Fuel and Power for Compressor Stations		
186	856 Mains Expenses		
187	857 Measuring and Regulating Station Expenses		
188	858 Transmission and Compression of Gas by Others		
189	859 Other Expenses		
190	860 Rents		
191	TOTAL Operation (Enter Total of lines 180 thru 190)	**None**	**None**
192	Maintenance		
193	861 Maintenance Supervision and Engineering		
194	862 Maintenance of Structures and Improvements		
195	863 Maintenance of Mains		
196	864 Maintenance of Compressor Station Equipment		
197	865 Maintenance of Measuring and Reg. Station Equipment		
198	866 Maintenance of Communication Equipment		
199	867 Maintenance of Other Equipment		
200	TOTAL Maintenance (Enter Total of lines 193 thru 199)	**None**	**None**
201	TOTAL Transmission Expenses (Enter Total of lines 191 and 200)	**None**	**None**
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	$ 932,760	$ 758,927
205	871 Distribution Load Dispatching	$ 514,554	$ 503,761
206	872 Compressor Station Labor and Expenses	$ 77,125	$ 58,618
207	873 Compressor Station Fuel and Power		

Name of Respondent	This Report is:	Date of Report	Year Ending
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
208	874 Mains and Services Expenses	$ 4,601,898	$ 3,161,495
209	875 Measuring and Regulating Station Expenses - General	$ 708,003	$ 640,204
210	876 Measuring and Regulating Station Expenses - Industrial	$ 151,563	$ 214,046
211	877 Measuring & Regulating Station Exp - City Gate Check Station	$ -	$ -
212	878 Meter and House Regulator Expenses	$ 1,350,743	$ 1,335,618
213	879 Customer Installations Expenses	$ 1,688,999	$ 1,546,729
214	880 Other Expenses	$ 4,261,747	$ 3,483,320
215	881 Rents	$ 84,695	$ 95,056
216	TOTAL Operation (Enter Total of lines 204 thru 215)	**$ 14,372,087**	**$ 11,797,774**
217	Maintenance		
218	885 Maintenance Supervision and Engineering	$ 45,097	$ 1,208
219	886 Maintenance of Structures and Improvements	$ 38,618	$ 20,724
220	887 Maintenance of Mains	$ 1,493,162	$ 1,193,413
221	888 Maintenance of Compressor Station Equipment	$ 18,187	$ 33,731
222	889 Maintenance of Meas. and Reg. Sta. Equip. - General	$ 488,774	$ 510,698
223	890 Maintenance of Meas. and Reg. Sta. Equip. - Industrial	$ 119,307	$ 88,977
224	891 Maint. of Meas. & Reg. Sta. Equip. - City Gate Check Station		
225	892 Maintenance of Services	$ 1,193,488	$ 781,543
226	893 Maintenance of Meters and House Regulators	$ 1,172,517	$ 921,687
227	894 Maintenance of Other Equipment	$ 489,198	$ 555,477
228	TOTAL Maintenance (Enter Total of lines 218 thru 227)	**$ 5,058,348**	**$ 4,107,458**
229	TOTAL Distribution Expenses (Enter Total of lines 216 and 228)	**$ 19,430,435**	**$ 15,905,233**
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	$ 55,114	$ 61,409
233	902 Meter Reading Expenses	$ 616,701	$ 553,573
234	903 Customer Records and Collection Expenses	$ 4,544,898	$ 4,029,461

Name of Respondent	This Report is:	Date of Report	Year Ending
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

GAS OPERATION AND MAINTENANCE EXPENSES (continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
235	904 Uncollectible Accounts	$ 2,480,745	$ 622,402
236	905 Miscellaneous Customer Accounts Expenses	$ 141,820	$ 25,321
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	**$ 7,839,278**	**$ 5,292,166**
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	$ -	$ -
241	908 Customer Assistance Expenses	$ 1,397,354	$ 1,379,141
242	909 Informational and Instructional Expenses	$ 108,027	$ 69,794
243	910 Miscellaneous Customer Service and Informational Expenses	$ -	$ 346
244	TOTAL Customer Service & Information Expenses (Lines 240 thru 243)	**$ 1,505,381**	**$ 1,449,281**
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	$ -	$ -
248	912 Demonstrating and Selling Expenses	$ -	$ -
249	913 Advertising Expenses	$ 10,310	$ 16,242
250	916 Miscellaneous Sales Expenses	$ -	$ -
251	TOTAL Sales Expenses (Enter Total of lines 247 thru 250)	**$ 10,310**	**$ 16,242**
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	$ 6,329,723	$ 6,503,911
255	921 Office Supplies and Expenses	$ 5,155,348	$ 5,789,220
256	(Less) (922) Administrative Expenses Transferred - Credit	$ (527,933)	$ (480,924)
257	923 Outside Services Employed	$ 852,593	$ 1,217,478
258	924 Property Insurance	$ 72,980	$ 83,806
259	925 Injuries and Damages	$ 982,732	$ 936,095
260	926 Employee Pensions and Benefits	$ 4,425,621	$ 5,668,468
261	927 Franchise Requirements	$ -	$ -
262	928 Regulatory Commission Expenses	$ 646	$ -
263	(Less) 929 Duplicate Charges - Credit	$ -	$ -
264	930.1 General Advertising Expenses	$ 67,608	$ 95,850
265	930.2 Miscellaneous General Expenses	$ 638,635	$ 633,506
266	931 Rents	$ 1,336,381	$ 1,366,556
267	TOTAL Operation (Enter Total lines 254 thru 266)	**$ 19,334,334**	**$ 21,813,966**
268	Maintenance		
269	932 Maintenance of General Plant	$ 56,493	$ 84,862
270	TOTAL Administrative and General Exp (Total of lines 267 and 269)	**$ 19,390,827**	**$ 21,898,828**
271	TOTAL Gas O. & M. Exp (Lines 97,177,201,229,237,244,251 and 270)	**$ 198,442,941**	**$ 234,062,916**

Name of Respondent Cascade Natural Gas Corporation	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report Dec. 31, 2012

EXCHANGE AND IMBALANCE TRANSACTIONS

1. Report below details by zone and rate schedule concerning the gas quantities and related dollar amount of imbalances associated with system balancing and no-notice service. Also, report certificated natural gas exchange transactions during the year. Provide subtotals for imbalance and no-notice quantities for exchanges. If respondent does not have separate zones, provide totals by rate schedule. Minor exchange transactions (less than 100,000 Dth) may be grouped.

Line No.	Zone/Rate Schedule (a)	Gas Received from Others Amount (b)	Gas Received from Others Dth (c)	Gas Delivered to Others Amount (d)	Gas Delivered to Others Dth (e)
1					
2	None				
3					
4					
5					
6					
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11					
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18					
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21					
22					
23					
24					
25	TOTAL -				

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec. 31, 2012**

GAS USED IN UTILITY OPERATIONS

1. Report below details of credits during the year to Accounts 810, 811, and 812

2. If any natural gas was used by the respondent for which a charge was not made to the appropriate expense or other account, list separately in column (c) the Dth of gas used, omitting entries in column (d).

Line No.	Purpose for Which Gas Was Used (a)	Account Charged (b)	Natural Gas Gas Used (Dth) (c)	Natural Gas Amount of Credit (in dollars) (d)	Natural Gas Amount of Credit (in dollars) (d)	Natural Gas Amount of Credit (in dollars) (d)
1	810 Gas used for Compressor Station Fuel - Credit					
2	811 Gas used for Products Extraction - Credit					
3	Gas Shrinkage and Other Usage in Respondent's Own Processing					
4	Gas Shrinkage, Etc. for Respondent's Gas Processed by Others					
5	812 Gas used for Other Utility Operations - Credit (Report separately for each principal use. Group minor uses)					
6						
7	Gas Used for Other Utility Operations	812	16,426	76,028		
8						
9						
11						
12						
13						
14						
15						
16						
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24						
25	TOTAL		16,426	76,028		

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

TRANSMISSION AND COMPRESSION OF GAS BY OTHERS (Account 858)

1. Report below details concerning gas transported or compressed for respondent by others equalling more than 1,000,000 Dth and amounts of payments for such services during the year. Minor items (less than 1,000,000) Dth may be grouped. Also, include in column (c) amounts paid as transition costs to an upstream pipeline.

2. In column (a) give name of companies, points of delivery and receipt of gas. Designate points of delivery and receipt so that they can be identified readily on a map of respondent's pipeline system.

3. Designate associated companies with an asterisk in column (b).

Line No.	Name of Company and Description of Service Performed (a)	* (b)	Amount of Payment (in dollar) (c)	Dth of Gas Delivered (d)
1	None			
2				
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23				
24				
25	TOTAL -			

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

OTHER GAS SUPPLY EXPENSES (Account 813)

1. Report other gas supply expenses by descriptive titles that clearly indicate the nature of such expenses. Show maintenance expenses, revaluation of monthly encroachments recorded in Account 117.4, and losses on settlements of imbalances and gas losses not associated with storage separately. Indicate the functional classification and purpose of property to which any expenses relate. List separately items of $250,000 or more.

Line No.	Description (a)	Amount (in dollars) (b)
1	Labor Expenses and applicable overhead charges	208,745
2	Vehicle Mileage	405
3	Airfare and related costs	2,985
4	Meals	908
5	Lodging	3,084
6	Office Supplies	278
7		
8		
9		
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11		
12		
13		
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35		
36		
37	TOTAL	$ 216,405

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec 31, 2012**

MISCELLANEOUS GENERAL EXPENSES (ACCOUNT 930.2)

1. Provide the information requested below on miscellaneous general expenses.
2. For Other Expenses, show the (a) purpose, (b) recipient and © amount of such items. List separately amounts of $250,000 or more however, amounts less than $250,000 may be grouped if the number of items of so grouped is shown.

Line No.	Description (a)	Amount (In dollars) (b)
1	Industry association dues	149,627
2	Experimental and general research expenses.	
	a. Gas Research Institute (GRI)	
	b. Other	
3	Publishing and distributing information and reports to stockholders, trustee, registrar, and transfer agent fees and expenses, and other expenses of servicing outstanding securities of the respondent	
4		
5	Bank and Other Finance Fees (paid to Bank of New York, Payflex and MDU for CNGC's share of corporate banking fees)	293,387
6		
7	Director's Fees (paid to MDU for CNGC's share of director's expenses)	245,169
8		
9	Miscellaneous under $250,000 (13 items)	(49,549)
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24	**TOTAL**	**638,634**

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☑ A Resubmission	Date of Report (Mo, Da, Yr)	Year Ending **Dec. 31, 2012**

DEPRECIATION, DEPLETION AND AMORTIZATION OF GAS PLANT

(Account 403, 404.1, 404.2, 404.3, 405)

(Except Amortization of Acquisition Adjustments)

1. Report in Section A the amounts of depreciation expense, depletion and amortization for the accounts indicated and classified according to the plant functional groups shown.

2. Report in Section B, column (b) all depreciable or amortizable plant balances to which rates are applied and show a composite total. (If more desirable, report by plant account, subaccount or functional classifications other than those pre-printed in column (a). Indicate in a footnote the manner in which column (b) balances are

Section A. Summary of Depreciation, Depletion, and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization and Depletion of Producing Natural Gas Land and Land Rights (Acct 404.1) (d)	Amortization of Underground Storage Land and Land Rights (Account 404.2) (e)
1	Intangible plant	-			923,958
2	Production plant, manufactured plant				
3	Production & gathering plant, natural gas				
4	Products extraction plant				
5	Underground gas storage plant				
6	Other storage plant				
7	Base load LNG terminating and processing plant				
8	Transmission plant	321,503			
9	Distribution plant	17,091,173			
10	General plant	1,038,501			
11	Common plant - gas				
12	**TOTAL -**	**18,451,177**		**-**	**923,958**

Name of Respondent	This Report is:	Date of Report	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

DEPRECIATION, DEPLETION AND AMORTIZATION OF GAS PLANT
(Account 403, 404.1, 404.2, 404.3, 405)
(Except Amortization of Acquisition Adjustments) (continued)

obtained. If average balancesare used, state the method of averaging used. For column (c) report available information for each plant functional classification listed in column (a). If composite depreciation accounting is used, report available information called for in columns (b) and (c) on this basis. Where the unit-of-production method is used to determine depreciation charges, show in a footnote any revisions made to estimated gas reserves.

3. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state in a footnote the amounts and nature of provisions and the plant items to which related.

Section A. Summary of Depreciation, Depletion, and Amortization Charges

Line No.	Amortization of Other Limited-Term Gas Plant (Account 404.3) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total (b to g) (h)	Functional Classification (a)
1			923,958	Intangible plant
2			-	Production plant, manufactured plant
3			-	Production & gathering plant, natural gas
4			-	Products extraction plant
5			-	Underground gas storage plant
6			-	Other storage plant
7			-	Base load LNG terminating and processing plant
8			321,503	Transmission plant
9			17,091,173	Distribution plant
10			1,038,501	General Plant
11			-	Common plant - gas
12	**-**	**-**	**19,375,135**	**Total**

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year Ending **Dec 31, 2012**

DEPRECIATION, DEPLETION AND AMORTIZATION OF GAS PLANT

(Account 403, 404.1, 404.2, 404.3, 405)

(Except Amortization of Aquistitions Adjustments) (Continued)

4. Add rows as necessary to completely report all data. Number the additional rows in sequence as 2.01, 2.02, 3.01, 3.02, etc.

Section B. Factors Used in Estimating Depreciation Charges

Line No.	Functional Classification (a)	Plant Bases (in thousands) (b)	Applied Depreciation or Amortization Rates (Percent) (c)
1	Production and Gathering Plant		
2	Offshore (footnote details)		
3	Onshore (footnote details)		
4	Underground gas storage plant (footnote details)		
5	Transmission Plant		
6	Offshore (footnote details)		
7	Onshore (footnote details)		
8	General Plant (footnote details)		
9			
10			
11			
12			
13			
14			
15			

Notes to Depreciation, Depletion and Amortization of Gas Plant

Depreciation is accrued monthly on the average balance in each plant account using a rate specific to the account. The average balance is the simple average of the balance at the beginning of the month and at the end of the month. The amounts shown below represent the year-end balances of depreciable plant and the weighted average composite rates based on year-end balances in each category.

	Washington		Oregon	
Description (a)	Depreciable Plant Base (Thousands) (b)	Composite Rate (Percent) (c)	Depreciable Plant Base (Thousands) (d)	Composite Rate (Percent) (e)
Intangible plant	13,079		4,280	
Manufactured gas production	0		0	
Transmission plant	11,155	1.88%	5,875	1.91%
Distribution plant	508,937	2.62%	141,285	2.66%
General plant	37,323	3.85%	12,236	3.76%
Total -	570,494	2.75%	163,676	2.78%

Name of Respondant	This Report is:	Date of Report	Year/Period of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	End of **Dec. 31, 2012**

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts

(a) Miscellaneous Amortization (Account 425)-Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions-Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than $250,000 may be grouped by classes within the above accounts

(c) Interest on Debt to Associated Companies (Account 430)-For each associated company that incurred interest on debt during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open accounts, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year

(d) Other Interest Expense (Account 431)-Report details including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)		Amount (b)
1	(a) Miscellaneous Amortization (Account 425)		**-**
2			
3	*(b) Miscellaneous Income Deductions (Account 426):*		
4	Donations (Account 426.1)		**221,908**
5			
6	Life Insurance (Account 426.2)		-
7			
8	*Penalties (Account 426.3):*		
9	**Payee**	**Nature**	
10			
11	Various	Miscellaneous	
12			-
13			
14	Expenditures for Certain Civic, Political and Related Activities (Account 426.4		**109,581**
15			
16	Other Deductions (426.5)		
17	**Payee**	**Nature**	
18	MDU/MDU Resources	CNGC Share of Corporate Development	60
19		**Total Miscellaneous Income Deductions (Account 426)**	**331,549**
20			
21	© Interest on Debt to Associated Companies (Account 430)		**-**
22			
23	*(d) Other Interest Expense (Account 431):*		
24	**Description**	**Interest Rate**	
25	Customer Deposits	Various	2,382
26	Deferral Accounts - WA	FERC Interest Rate	676,422
27	Deferral Accounts - OR	***	512,911
28	Interest on Short-Term Debt	Various	105,141
29	Other	Various	45,296
30		**Total Other Interest Expense (Account 431)**	**1,342,152**
31			
32	*** Accounts not amortizing - 8.709% (Overall rate of return granted in the last Oregon general rate filing); Accounts amortizing - 2.01%		
33			

Name of Respondant	This Report is:	Date of Report	Year/Period of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	End of Dec. 31, 2012

Regulatory Commission Expense (Account 928)

1. Report below details of regulatory commission expenses incurred during the current year (or in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party.

2. In colums (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

Line No.	Description (Furnish name of regulatory commission or body, the docket number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Oregon PUC audit	646	-	646	-
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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15					
16					
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21					
22					
23					
24					
25	**Total**	**646**	**-**	**-**	**-**

Name of Respondant **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report End of Dec. 31, 2012

Regulatory Commission Expense (Account 928)

3. Show in Column (k) any expenses incurred in prior years that are being amortized. List in column (a) the period of amortization.

4. Identify separately all annual charge adjustments (ACA).

5. List in column (f), (g), and (h) expenses incurred during the year which were charged currently to income, plant, or other accounts.

6. Minor items (less than $250,000) may be grouped.

	Expenses Incurred During Year Charged Currently to	Expenses Incurred During Year Charged Currently To	Expenses Incurred During Year Charged Currently To	Expenses Incurred During Year	Amortized During Year	Amortized During Year Amount	Deferred in Account 182.3 End of Year
	Department	Account No.	Amount	Deferred to Acct 182.3	Contra Account	Amount	
Line No.	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Regulatory Affairs	928	646	-	-	-	-
2							
3							
4							
5							
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23							
24							
25			**646**	**-**	**-**	**-**	**-**

Name of Respondent	This Report Is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

EMPLOYEE PENSIONS AND BENEFITS (Account 926)

1. Report below the items contained in Account 926, Employee Pensions and Benefits

Line No.	Expense (a)	Amound (b)
1	Pensions - defined benefit plants	568,697
2	Pensions - other	1,045,466
3	Post-retirement benefits other than pensions (PBOP)	363,614
4	Post-employment beneift plans	79,053
5	Other (Specify)	
6	Medical/Dental	2,207,061
7	Various	164,239
8		
9		
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28		
	Total	4,428,130

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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec. 31, 2012

Distribution of Salaries and Wages

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. Salaries and wages billec to the Respondent by an affiliated company must be assigned to the particular operation function(s) relating to the expenses

In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correc results may be used. When reporting detail of other accounts, enter as many rows as necessary numbered sequentially starting with 75.01, 75.02, etc

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
1	Electric				
2	Operation				
3	Production				
4	Transmission				
5	Distribution				
6	Customer Accounts				
7	Customer Service and Informational				
8	Sales				
9	Administrative and General				
10	TOTAL Operation (Total of lines 3 thru 9)				
11	Maintenance				
12	Production				
13	Transmission				
14	Distribution				
15	Administrative and General				
16	TOTAL Maintenance (Total of lines 12 thru 15)				
17	Total Operation and Maintenance				
18	Production (Total of lines 3 and 12)				
19	Transmission (Total of lines 4 and 13)				
20	Distribution (Total of lines 5 and 14)				
21	Customer Accounts (Line 6)				
22	Customer Service and Informational (Line 7)				
23	Sales (Line 8)				
24	Administrative and General (Total of lines 9 and 15)				
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)				
26	Gas				
27	Operation				
28	Production-Manufactured Gas				
29	Production-Natural Gas (Including Exploration and Development)				
30	Other Gas Supply				
31	Storage, LNG Terminaling and Processing				
32	Transmission				
33	Distribution	8,268,594			
34	Customer Accounts	4,037,028			
35	Customer Service and Informational	0			
36	Sales	0			
37	Administrative and General	5,133,385			
38	TOTAL Operation (Total of lines 28 thru 37)	**17,439,007**	**0**	**0**	**17,439,007**
39	Maintenance				
40	Production-Manufactured Gas				
41	Production-Natural Gas (Including Exploration and Development)				
42	Other Gas Supply				
43	Storage, LNG Terminaling and Processing				
44	Transmission				
45	Distribution	2,650,353			

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec. 31, 2012**

Distribution of Salaries and Wages (continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
46	Administrative and General				
47	TOTAL Maintenance (Total of lines 40 thru 46)	**2,650,353**	**0**	**0**	**2,650,353**
48	Gas (Continued)				
49	Total Operation and Maintenance				
50	Production-Manufactured Gas (Total of lines 28 and 40)				
51	Production-Natural Gas (Including Expl. and Dev.) (ll. 29 and 41)				
52	Other Gas Supply (Total lines 30 and 42)				
53	Storage, LNG Terminaling and Processing (Total of ll. 31 and 43)				
54	Transmission (Total of lines 32 and 44)				
55	Distribution (Total of lines 33 and 45)	10,918,947			
56	Custormer Accounts (Total of line 34)	4,037,028			
57	Customer Service and Informational (Total of line 35)	0			
58	Sales (Total of line 36)	0			
59	Administrative and General (Total of lines 37 and 46)	5,133,385			
60	TOTAL Operation and Maintenance (Total of lines 50 thru 59)	**20,089,360**	**0**	**0**	**20,089,360**
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL All Utility Dept. (Total of lines 25, 60, and 62)	**20,089,360**	**0**	**0**	**20,089,360**
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	6,126,242			
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	**6,126,242**	**0**	**0**	**6,126,242**
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	222,769			
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	**222,769**	**0**	**0**	**222,769**
75					
		42,640			
		3,245			
76	TOTAL Other Accounts	**45,885**	**0**	**0**	**45,885**
77	TOTAL SALARIES AND WAGES	**26,484,256**	**0**	**0**	**26,484,256**

Name of Respondant **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year/Period of Report End of **Dec. 31, 2012**

Charges for Outside Professional and Other Consultative Services

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising, labor relations, and public relations rendered for the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation, partnershp, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $250,000, including payments for legislative services, except those which should be reported in Account 426.4 Expenditures for Certain Civic, Political, and Related Activities.

(a)Name of person or organization rendering services.

(b) Total charges for the year.

2. Sum under a description "Other", all of the aforementioned services amounting to $250,000 or less.

3. Total under a description "Total", the total of all of the aforementioned services.

4. Charges for outside professional and other consultative services provided by associated (affiliated) companies should be excluded from this schedule and be reported on Page 358, according to the instructions for that schedule.

Line No.	Description (a)	Amount (in dollars) (b)
1	Pilchuck Contractors Inc	5,791,180
2	Snelson Companies Inc	3,710,030
3	Northwest Metal Fabrication and Pipe Inc	3,252,727
4	Prosource Tech Inc	1,109,733
5	Mears Group Inc	497,814
6	Day Wireless Systems	455,472
7	Northwest Pipeline Group	376,200
8	JTI Commercial Service	279,156
9	Other	5,952,253
10		
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23		
24		
25	**Total**	**21,424,565**

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec. 31, 2012**

Transactions with Associated (Affiliated) Companies

1. Report below the information called for concerning all goods or services received from or provided to associated (affiliated) companies amounting to more than $250,000.
2. Sum under a description "Other", all of the aforementioned goods and services amounting to $250,000 or less.
3. Total under a description "Total", the total of all of the aforementioned goods and services.
4. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote the basis of the allocation.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Goods of Services Provided by Affiliated Companies			
2				
3		IGC/MDU/MDUR	107	5,149,094
4				
5		IGC/MDU/MDUR	426.1	8,955
6				
7		IGC/MDU/MDUR	426.4	3,727
8				
9		IGC/MDU/MDUR	813	185,730
10				
11		IGC/MDU/MDUR	875	143,803
12				
13		IGC/MDU/MDUR	880	255,221
14				
15		IGC/MDU/MDUR	902	126,108
16				
17		IGC/MDU/MDUR	903	4,214,963
18				
19		IGC/MDU/MDUR	909	1,857
20	Goods of Services Provided for Affiliated Companies			
21		IGC/MDU/MDUR	920	4,265,246
22				
23		IGC/MDU/MDUR	921	3,536,154
24				
25		IGC/MDU/MDUR	922	(2,681)
26				
27		IGC/MDU/MDUR	923	236,186
28				
29		IGC/MDU/MDUR	925	737
30				
31		IGC/MDU/MDUR	926	138,080
32				
33		IGC/MDU/MDUR	930.1	34,099
34				
35		IGC/MDU/MDUR	930.2	212,359
36				
37		IGC/MDU/MDUR	931	1,287,717
38				
39		Other Services	VAR	337,518
40				
41				
42				**20,134,873**

Name of Respondent	This Report is:	Date of Report	Year Ending
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

COMPRESSOR STATIONS

1 Report below details concerning compressor stations. Use the following subheadings: field compressor stations products extraction compressor stations, underground storage compressor stations, transmission compressor stations, distribution compressor stations, and other compressor stations.

2 For the column (a), indicate the production areas where such stations are used. Group relatively small field compressor stations by production areas. Show the number of stations grouped. Identify any station held under a title other than full ownership. State in a footnote the name of owner or co-owners, the nature of respondent's title, and percent of ownership if jointly owned.

Line No.	Name of Station and Location (a)	Number of Units at Station (b)	Certificated Horsepower for Each Station (c)	Plant Cost (d)
1	Compressor Station at Burlington, WA Placed in Service: Aug, 2001	1	1350 HP	$ 2,000,730
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
	Total -			**$ 2,000,730**

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year Ending **Dec. 31, 2012**

COMPRESSOR STATIONS (continued)

Designate any station that was not operated during the past year. State in footnote whether the book cost of such station has been retired in the books of account, or what disposition of the station and its book cost are comtemplated. Designate any compressor units in transmission compressor stations installed and put into operation during the year and show in a footnote each unit's size and the date the unit was placed in operation.

3. For column (e), include the type of fuel or power, if other than natural gas. If two types of fuel or power are used, show separate entries for natural gas and the other fuel or power.

Line No.	Expenses (Except depreciation and taxes) Fuel (e)	Expenses (Except depreciation and taxes) Power (f)	Expenses (Except depreciation and taxes) Other (g)	Gas for Compressor Fuel in Dth (h)	Electricity for Compressor Station in kWh (i)	Operational Data Total Compressor Hours of Operation During Year (j)	Operational Data No. of Compressors Operated at Time of Station Peak (k)	Date of Station Peak (l)
1	$ 3,147	$ -	$ 109,194			Not available	1	Not available
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	$ 3,147	**$ -**	**$ 109,194**					

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

GAS STORAGE PROJECTS

1. Report injections and withdrawals of gas for all storage projects used by respondent.

Line No.	Item (a)	Gas Belonging to Respondent (Dth) (b)	Gas Belonging to Others (Dth) (c)	Total Amount (Dth) (d)
	STORAGE OPERATIONS (In Dth)			
1	Gas Delivered to Storage			
2	January			
3	February			
4	March			
5	April			
6	May			
7	June			
8	July			
9	August			
10	September			
11	October			
12	November			
13	December			
14	TOTAL (Total of lines 2 through 13)	None	None	None
15	Gas Withdrawn from Storage			
16	January			
17	February			
18	March			
19	April			
20	May			
21	June			
22	July			
23	August			
24	September			
25	October			
26	November			
27	December			
28	TOTAL (Total of lines 16 through 27)	None	None	None

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report **Dec. 31, 2012**

GAS STORAGE PROJECTS (continued)

1. On line 4, enter the total storage capacity Certificated by FERC.

2. Report total amount of Dth or other unit, as applicable on lines 2, 3, 4, 7. If quantity is converted from Mcf to Dth, provide conversion factor in a footnote.

Line No.	Item (a)			Total Amount (b)
	STORAGE OPERATIONS			
1	Top or Working Gas End of Year			
2	Cushion Gas (Including Native Gas)			
3	Total Gas in Reservoir (Total of Line 1 and 2)			
4	Certificated Storage Capacity			
5	Number of injection - Withdrawal Wells			
6	Number of Observation Wells			
7	Maximum Days' Withdrawal from Storage			
8	Date of Maximum Days' Withdrawal			
9	LNG Terminal Companies (in Dth)			
10	Number of Tanks			
11	Capacity of Tanks			
12	LNG Volume			
13	Received at "Ship Rail"			
14	Transferred to Tanks			
15	Withdrawn from Tanks			
16	"Boil Off" Vaporization Loss			

Name of Respondent **Cascade Natural Gas Corporation**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report **Dec. 31, 2012**

TRANSMISSION LINES

1. Report below, by state, the total miles of transmission lines of each transmission system operated by respondent at end of year.
2. Report separately any lines held under a title other than full ownership. Designate such lines with an asterisk in column (b), and in a footnote state the name of owner, or co-owner, nature of respondent's title, and percent of ownership if jointly owned.
3. Report separately any line that was not operated during the past year. Enter in a footnote the details and state whether the book cost of such a line, or any portion thereof, has been retired in the books of account, or what disposition of the line and its book costs are contemplated.
4. Report the number of miles of pipe to one decimal point.

Line No.	Designation (Identification) of Line or Group of Lines (a)		* (b)	Total Miles of Pipe (c)
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2012

TRANSMISSION SYSTEM PEAK DELIVERIES

1. Report below the total transmission system deliveries of gas (in Dth), excluding deliveries to storage, for the period of system peak deliveries indicated below, during the 12 months embracing the heating season overlapping the year's end for which this report is submitted. The season's peak normally will be reached before the due date of this report, April 30, which permits inclusion of the peak information required on this page. Add rows as necessary to report all data. Number additional rows 6.01, 6.02, etc.

Line No.	Description	Dth of Gas Delivered to Interstate Pipelines (b)	Dth of Gas Delivered to Others (c)	Total (b) + (c) (d)
	SECTION A: SINGLE DAY PEAK DELIVERIES			
1				
2	Volumes of Gas Transported			
3	No-Notice Transportation			
4	Other Firm Transportation			
5	Interruptible Transportation			
6				
7	TOTAL			NA
8	Volumes of gas withdrawn from storage under Storage Contract			
9	No-Notice Transportation			
10	Other Firm Transportation			
11	Interruptible Transportation			
12				
13	TOTAL			NA
14	Other Operational Activities			
15	Gas withdrawn from storage for system operations			
16	Reduction in Line Pack			
17				
18	TOTAL			NA
19	SECTION B: CONSECUTIVE THREE-DAY PEAK DELIVERIES			
20				
21	Volumes of Gas Transported			
22	No-Notice Transportation			
23	Other Firm Transportation			
24	Interruptible Transportation			
25				
26	TOTAL			NA
27	Volumes of gas withdrawn from storage under Storage Contracts			
28	No-Notice Transportation			
29	Other Firm Transportation			
30	Interruptible Transportation			
31				
32	TOTAL			NA
33	Other Operational Activities			
34	Gas withdrawn from storage for system operations			
35	Reduction in Line Pack			
36				
37	TOTAL			NA

Name of Respondent **Cascade Natural Gas Corporation**	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report **Dec. 31, 2012**

AUXILIARY PEAKING FACILITIES

1. Report below auxiliary facilities of the respondent for meeting seasonal peak demands on the respondent's system, such as underground storage projects, liquefied petroleum gas installations, gas liquefaction plants, oil gas sets, etc.
2. For column (c) , for underground storage projects, report the delivery capacity on February 1 of the heating season overlapping the year-end for which this report is submitted. For other facilities, report the rated maximum daily delivery capacities.
3. For column (d), include or exclude (as appropriate) the cost of any plant used jointly with another facility on the basis of predominant use, unless the auxiliary peaking facility is a separate plant as contemplated by general instruction 12 of the Uniform System of Accounts.

Line No.	Location of Facility (a)	Type of Facility (b)	Maximum Daily Delivery Capacity of Facility Dth (c)	Cost of Facility (in dollars) (d)	Was Facility Operated on Day of Highest Transmission Peak Delivery? (e)
1	**None**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of Report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		Dec. 31, 2012

GAS ACCOUNT - NATURAL GAS

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the year to date Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Enter in column (d) the respective quarter's Dth as reported in the schedules indicated for the items of receipts and deliveries.
5. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the line on which such quantities are listed.
6. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose.
7. Indicate by footnote the quantities of gas not subject to Commission regulation which did not incur FERC regulatory costs by showing (1) the local distribution volumes another jurisdictional pipeline delivered to the local distribution company portion of the reporting pipeline (2) the quantities that the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities and which the reporting pipeline received through gathering facilities or intrastate facilities, but not through any of the interstate portion of the reporting pipeline, and (3) the gathering line quantities that were not destined for interstate market or that were not transported through any interstate portion of the reporting pipeline.
8. Indicate in a footnote the specific gas purchase expense account(s) and related to which the aggregate volumes reported on line No. 3 relate.
9. Indicate in a footnote (1) the system supply quantities of gas that are stored by the reporting pipeline, during the reporting year and also reported as sales transportation and compression volumes by the reporting pipeline during the same reporting year, (2) the system supply quantities of gas that are stored by the reporting reporting pipeline, during the reporting year which the reporting pipeline intends to sell or transport in a future reporting year, and (3) contract storage quantities.
10. Also indicate the volumes of pipeline production field sales that are included in both the company's total sales figure and the company's total transportation figure. Add additional information as necessary to the footnotes.

Line No.	Item (a)	Ref. Page No. of FERC Form Nos. 2/2-A (b)	Total Amount of Dth Year to Date (c)	Current 3 months Ended Amount of Dth Quarterly Only (d)
01	Name of System:			
2	**GAS RECEIVED**			
3	Gas purchases (Accounts 800-805)		28,770,344	0
4	Gas of others received for gathering (Account 489.1)	303	0	0
5	Gas of others received for transmission (Account 489.2)	305	0	0
6	Gas of others received for distribution (Account 489.3)	301	0	0
7	Gas of others received for contract storage (Account 489.4)	307	0	0
8	Gas of others received for Production/Extraction/Processing (Account 490 and 491)		0	0
9	Exchanged gas received from others (Account 806)	328	0	0
10	Gas received as imbalances (Account 806)	328	0	0
11	Receipts of respondent's gas transported by others (Account 858)	332	0	0
12	Other gas withdrawn from storage (Explain)		576,505	0
13	Gas received from shippers as compressor station fuel		0	0
14	Gas received from shippers as lost and unaccounted for		0	0
15			84,552,419	0
16	Total Receipts (Total of Lines 3 thru 14) -		113,899,268	0
17	**GAS DELIVERED**			
18	Gas sales (Accounts 480-484)		28,616,848	0
19	Deliveries of gas gathered for others (Account 489.1)	303	0	0
20	Deliveries of gas transported for others (Account 489.2)	305	84,552,419	0
21	Deliveries of gas distributed for others (Account 489.3)	301	0	0
22	Deliveries of contract storage gas (Account 489.4)	307	0	0
23	Gas of others received for Production/Extraction/Processing (Account 490 and 491)		0	0
24	Exchange gas delivered to others (Account 806)	328	0	0
25	Gas delivered as imbalances (Account 806)	328	0	0
26	Deliveries of gas to others for transportation (Account 858)	332	0	0
27	Other gas delivered to storage (Explain)		774,613	0
28	Gas used for compressor station fuel	509	0	0
29		331	16,426	0
30	Total Deliveries (Total Lines 17 thru 27) -		113,960,306	0
31	**GAS LOSSES AND GAS UNACCOUNTED FOR**			
32	Gas Losses and Gas Unaccounted For		(61,038)	0
33	**TOTALS**			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of Lines 30 and 32)		113,899,268	0

Name of Respondent	This Report is:	Date of Report	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	**Dec. 31, 2012**

SYSTEM MAPS

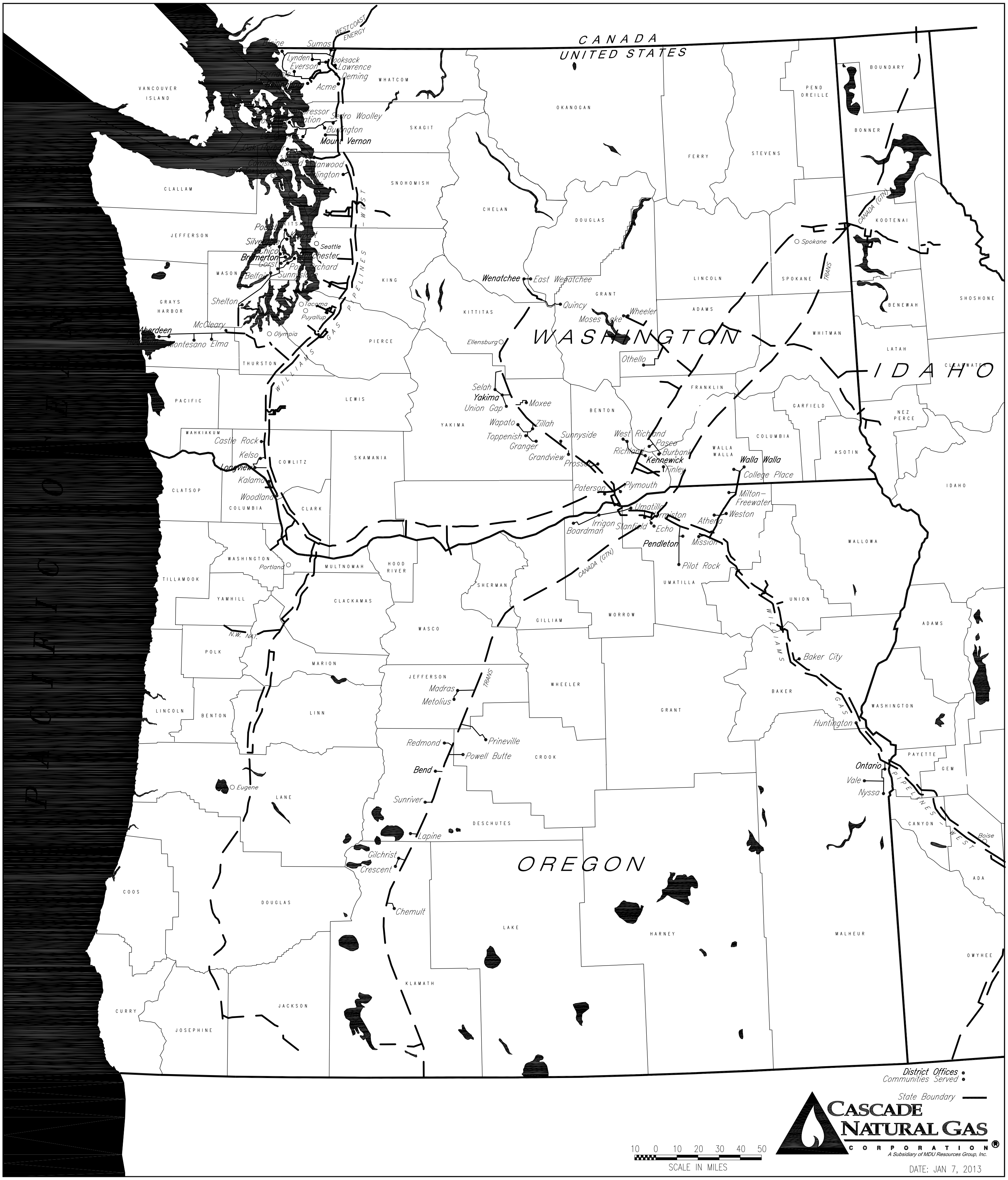
1. Furnish five copies of a system map (one with each filed copy of this report) of the facilities operated by the respondent for the production, gathering, transportation, and sale of natural gas. New maps need not be furnished if no important change has occurred in the facilities operated by the respondent since the date of the maps furnished with a previous year's annual report. If, however, maps are not furnished for this reason, reference should be made in the space below to the year's annual report with which the maps were furnished.

2. Indicate the following information on the maps:
   - (a) Transmission lines.
   - (b) Incremental facilities.
   - (c) Location of gathering areas.
   - (d) Location of zones and rate areas.
   - (e) Location of storage fields.
   - (f) Location of natural gas fields.
   - (g) Location of compressor stations.
   - (h) Normal direction of gas flow (indicated by arrows).
   - (i) Size of pipe.
   - (j) Location of products extraction plants, stabiliztion plants, purification plants, recycling areas, etc.
   - (k) Principal communities receiving service through the respondent's pipeline.

3. In addition, show on each map: graphic scale of the map; date of the facts the map purports to show, a legend giving all symbols and abbreviations used; designations of facilities leased to or from another company, giving name of such other company.

4. Maps not larger than 24 inches square are desired. If necessary, however, submit larger maps to show essential information. Fold the maps to a size not larger than this report. Bind the maps to the report.

SEE MAP NEXT PAGE


CANADA
UNITED STATES
WASHINGTON
OREGON
IDAHO
PACIFIC OCEAN
WEST COAST ENERGY
WILLIAMS GAS PIPELINES – WEST
CANADA (GTN)
TRANS CANADA
N.W. NAT.
VANCOUVER ISLAND
CLALLAM
JEFFERSON
MASON
GRAYS HARBOR
PACIFIC
WAHKIAKUM
COWLITZ
CLARK
SKAMANIA
LEWIS
THURSTON
PIERCE
KING
SNOHOMISH
SKAGIT
WHATCOM
OKANOGAN
CHELAN
DOUGLAS
KITTITAS
YAKIMA
BENTON
FRANKLIN
GRANT
ADAMS
LINCOLN
FERRY
STEVENS
PEND OREILLE
SPOKANE
WHITMAN
GARFIELD
COLUMBIA
WALLA WALLA
ASOTIN
BOUNDARY
BONNER
KOOTENAI
SHOSHONE
BENEWAH
LATAH
CLEARWATER
NEZ PERCE
IDAHO
ADAMS
WASHINGTON
PAYETTE
GEM
CANYON
ADA
OWYHEE
CLATSOP
COLUMBIA
WASHINGTON
TILLAMOOK
YAMHILL
MULTNOMAH
HOOD RIVER
CLACKAMAS
POLK
MARION
LINCOLN
BENTON
LINN
LANE
WASCO
SHERMAN
GILLIAM
MORROW
UMATILLA
UNION
WALLOWA
BAKER
JEFFERSON
WHEELER
GRANT
CROOK
DESCHUTES
HARNEY
MALHEUR
LAKE
KLAMATH
DOUGLAS
COOS
CURRY
JOSEPHINE
JACKSON
Blaine
Sumas
Lynden
Everson
Nooksack
Lawrence
Deming
Acme
Sedro Woolley
Burlington
Mount Vernon
Arlington
Seattle
Bremerton
Silverdale
Gorst
Port Orchard
Belfair
Sunnyslope
Shelton
Tacoma
Puyallup
Olympia
McCleary
Aberdeen
Montesano
Elma
Castle Rock
Kelso
Longview
Kalama
Woodland
Portland
Wenatchee
East Wenatchee
Quincy
Moses Lake
Wheeler
Othello
Ellensburg
Selah
Yakima
Union Gap
Moxee
Wapato
Zillah
Toppenish
Granger
Sunnyside
Grandview
Prosser
West Richland
Richland
Pasco
Burbank
Kennewick
Finley
Walla Walla
College Place
Milton-Freewater
Weston
Athena
Plymouth
Paterson
Umatilla
Hermiston
Irrigon
Boardman
Stanfield
Echo
Pendleton
Mission
Pilot Rock
Spokane
Baker City
Huntington
Ontario
Vale
Nyssa
Boise
Madras
Metolius
Redmond
Prineville
Powell Butte
Bend
Sunriver
Lapine
Gilchrist
Crescent
Chemult
Eugene
District Offices
Communities Served
State Boundary
10 0 10 20 30 40 50
SCALE IN MILES
CASCADE NATURAL GAS CORPORATION
A Subsidiary of MDU Resources Group, Inc.
DATE: JAN 7, 2013

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year of report
Cascade Natural Gas Corporation	(1) ☑ An Original (2) ☐ A Resubmission		**Dec. 31, 2012**

FOOTNOTE REFERENCE

Page No. (a)	Line or Item No. (b)	Column No. (c)	Footnote No. (d)
	None		

Name of Respondent Cascade Natural Gas Corporation	This Report is: (1) ☑ An Original (2) ☐ A Resubmission	Date of Report (Mo, Da, Yr)	Year of report Dec. 31, 2012

FOOTNOTE TEXT

Footnote No. (a)	Footnote Text (b)
	None

INDEX

THIS FILING IS	
Item 1: ■ An Initial (Original) Submission	OR ☐ Resubmission No. ____

Form 2 Approved
OMB No.1902-0028
(Expires 10/31/2014)

Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

SUPPLEMENTAL REPORT TO

OREGON PUBLIC UTILITY COMMISSION

FERC FINANCIAL REPORT
FERC FORM No. 2: Annual Report of Major Natural Gas Companies and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
Cascade Natural Gas Corporation	End of 2012

ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FROM 2
FOR MULTI-STATE GAS COMPANIES
2012

INDEX

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - STATEMENT OF OPERATING INCOME FOR THE YEAR

LINE NO.	ACCOUNT (a)	(REF.) PAGE NO. (b)	GAS UTILITY Current Year (c)	GAS UTILITY Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	68,132,016	80,606,310
3	Operating Expenses			
4	Operation Expenses (401)	4-9	49,459,374	59,996,562
5	Maintenance Expenses (402)	4-9	1,132,300	1,018,109
6	Depreciation Expense (403)	10	4,116,669	4,257,760
7	Amortization & Depletion of Utility Plant (404-405)	10	226,647	171,985
8	Amortization of Utility Plant Acquisition Adjustment (406)	10	-	-
9	Amortization of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)		-	-
10	Amortization of Conversion Expenses (407)		368,759	(305,000)
11	Taxes Other Than Income Taxes (408.1)	11	4,679,074	5,085,887
12	Income Taxes - Federal (409.1)	12	(318,693)	546,689
13	Income Taxes - Other (409.1)	13	(87,115)	(45,800)
14	Provision for Deferred Income Taxes (410.1)	14-21	2,890,050	1,946,522
15	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	14-21	-	-
16	Investment Tax Credit Adjustment - Net (411.4)	22	(4,372)	(18,376)
17	(Less) Gains from Disposition of Utility Plant (411.6)		-	-
18	Losses from Disposition of Utility Plant (411.7)		-	-
19	TOTAL Utility Operating Expenses (Enter Total of lines 4 through 18)		62,462,693	$ 72,654,338
20	Net Utility Operating Income (Enter Total of line 2 less 19)		5,669,323	$ 7,951,972

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURALGAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - GAS OPERATING REVENUES (ACCOUNT 400)

LINE NO.	ACCOUNT (a)	OPERATING REVENUES CURRENT YEAR (b)	OPERATING REVENUES PREVIOUS YEAR (c)	MCF OF NATURAL GAS SOLD CURRENT YEAR (d)	MCF OF NATURAL GAS SOLD PREVIOUS YEAR (e)	AVG. NO. OF NAT. GAS CUSTUMERS PER MO. CURRENT YEAR (f)	AVG. NO. OF NAT. GAS CUSTUMERS PER MO. PREVIOUS YEAR (g)
1	GAS SERVICE REVENUES						
2	480 Residential Sales	$ 36,929,039	$ 44,026,559	3,609,192	3,852,695	55,366	54,891
3	481 Commercial and Industrial Sales						
4	Small or Commercial	$ 22,747,154	$ 26,889,533	2,582,198	2,752,602	9,405	9,367
5	Large or Industrial	$ 4,214,339	$ 5,481,389	548,722	624,579	98	97
6	482 Other Sales to Public Authorities						
7	484 Interdepartmental Sales						
8	TOTAL Sales to Ultimate Consumers	$ 63,890,532	$ 76,397,481	6,740,112	7,229,876	64,869	64,355
9	483 Sales for Resale						
10	TOTAL Natural Gas Service Revenues	$ 63,890,532	$ 76,397,481	6,740,112	7,229,876	64,869	64,355
11	Revenues from Manufactured Gas						
12	TOTAL Gas Service Revenues	$ 63,890,532	$ 76,397,481				
13	OTHER OPERATING REVENUES						
14	485 Intracompany Transfers						
15	487 Forfeited Discounts						
16	488 Miscellaneous Service Revenues	$ 200,825	$ 276,004				
17	489 Revenue from Trans. of Gas of Others	$ 4,012,257	$ 3,913,606				
18	490 Sales of Prod. Ext. from Natural Gas						
19	491 Revenue from Natural Gas Proc. by Others						
20	492 Incidental Gasoline and Oil Sales						
21	493 Rent from Gas Property	$ 11,000	$ 13,000				
22	494 Interdepartmental Rents						
23	495 Other Gas Revenues	$ 17,402	$ 6,219				
24	TOTAL Other Operating Revenues	$ 4,241,484	$ 4,208,829				
25	TOTAL Gas Operating Revenues	$ 68,132,016	$ 80,606,310				
26	(Less) 496 Provision for Rate Refunds						
27	TOTAL Gas Operating Revenues Net of Provision for Refunds	$ -	$ -				
28	Dist. Type Sales by States (*Incl. Main Line Sales to Residential and Commercial Customers)*	$ 59,676,193		6,191,390			
29	Main Line Industrial Sales *(Incl. Main Line Sales to Public Authorities)*	$ 4,214,339		548,722			
30	Sales for Resale						
31	Other Sales to Public Authority (Local Dist. Only)						
32	Interdepartmental Sales						
33	TOTAL *(Same as Line 10, Columns (b) and (d))*	$ 63,890,532		6,740,112			

NOTES:

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - INTERDEPARTMENTAL SALES - NATURAL GAS (Account 484)

Report particulars concening sales of natural gas included in Account 484.

LINE NO.	DEPARTMENT AND BASIS OF CHARGES (a)	POINT OF DELIVERY (b)	MCF (14.74 psia AT 60 F) (c)	REVENUE (d)
	NONE			

RENT FROM GAS PROPERTY AND INTERDEPARTMENTAL RENTS (Accounts 493, 494)

1. Report particulars concerning rents received, included in Accounts 493 and 494.
2. Minor rents may be entered at the total amount for each class of such rents.
3. If rents are included which were arrived at under an arrangement for apportioning expenses of a joint facility, whereby the amount included in this account represents profit or return on property, depreciation, and taxes, give particulars and the basis of apportionment of such charges to Account493 or 494.
4. Provide a subheading and total for each account.

LINE NO.	NAME OF LESSEE OR DEPARTMENT (Designate associated companies) (a)	DESCRIPTION OF PROPERTY (b)	AMOUNT OF REVENUE FOR YEAR NATURAL GAS PROPERTY (c)	AMOUNT OF REVENUE FOR YEAR MANUFACTURED GAS PROPERTY (d)
	Account 493			
	Stone Bros., Inc.	Northern portion of parking lot at the Hermiston office for a latte stand	$ 11,000	
	Allocation of Rent Paid by MDUR Group		$ -	
	Total Account 493		$ 11,000	

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnotes.

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
1	1. PRODUCTION EXPENSES		
2	A. Manufactured Gas Production		
3	Manufactured Gas Production (Detail Page 4A)	**0**	**0**
4	B. Natural Gas Production		
5	B1. Natural Gas Production and Gathering		
6	Operation		
7	750 Operation Supervision and Engineering		
8	751 Production Maps and Records		
9	752 Gas Wells Expenses		
10	753 Field Lines Expenses		
11	754 Field Compressor Station Expenses		
12	755 Field Compressor Station Fuel and Power		
13	756 Field Measuring and Regulating Station Expenses		
14	757 Purification Expenses		
15	758 Gas Well Royalties		
16	759 Other Expenses		
17	760 Rents		
18	Total Operation (Enter Total of lines 7 thru 17)	**None**	**None**
19	Maintenance		
20	761 Maintenance Supervision and Engineering		
21	762 Maintenance of Structures and Improvements		
22	763 Maintenance of Producing Gas Wells		
23	764 Maintenance of Field Lines		
24	765 Maintenance of Field Compressor Station Equipment		
25	766 Maintenance of Field Meas. and Reg. Sta. Equipment		
26	767 Maintenance of Purification Equipment		
27	768 Maintenance of Drilling and Cleaning Equipment		
28	769 Maintenance of Other Equipment		
29	TOTAL Maintenance (Enter Total of lines 20 thru 28)	**None**	**None**
30	TOTAL Natural Gas Production & Gathering (Total of lines 18 and 29)	**None**	**None**
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering		
34	771 Operation Labor		
35	772 Gas Shrinkage		
36	773 Fuel		
37	774 Power		
38	775 Materials		
39	776 Operation Supplies and Expenses		
40	777 Gas Processed by Others		
41	778 Royalties on Products Extracted		
42	779 Marketing Expenses		
43	780 Products Purchases for Resale		
44	781 Variation in Products Inventory		
45	(Less) 782 Extracted Products Used by the Utility - Credit		
46	783 Rents		
47	TOTAL Operation (Enter Total of lines 33 thru 46)	**None**	**None**

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
1	A. Manufactured Gas Production Detail		

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2012

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
	B2. Products Extraction (Con't)		
48	Maintenance		
49	784 Maintenance Supervision and Engineering		
50	785 Maintenance of Structures and Improvements		
51	786 Maintenance of Extraction and Refining Equipment		
52	787 Maintenance of Pipe Lines		
53	788 Maintenance of Extracted Products Storage Equipment		
54	789 Maintenance of Compressor Equipment		
55	790 Maintenance of Gas Measuring and Reg. Equipment		
56	791 Maintenance of Other Equipment		
57	TOTAL Maintenance (Enter Total of lines 49 thru 56)	**None**	**None**
58	TOTAL Products Extraction (Enter Total of lines 47 and 57)	**None**	**None**
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals		
62	796 Nonproductive Well Drilling		
63	797 Abandoned Leases		
64	798 Other Exploration		
65	TOTAL Exploration & Development (Enter Total of lines 61 thru 64)	**None**	**None**
	D. Other Gas Supply Expenses		
66	Operation		
67	800 Natural Gas Well Head Purchases		
68	800.1 Natural Gas Well Head Purchases, Intracompany Transfers		
69	801 Natural Gas Field Line Purchases		
70	802 Natural Gas Gasoline Plant Outlet Purchases		
71	803 Natural Gas Transmission Line Purchases		
72	804 Natural Gas City Gate Purchases	$ 34,578,421	$ 45,198,896
73	804.1 Liquefied Natural Gas Purchases		
74	805 Other Gas Purchases		
75	(Less) 805.1 Purchased Gas Cost Adjustments	$ 3,527,349	$ 3,982,488
76	805.2 Incremental Gas Cost Adjustments		
77	TOTAL Purchased Gas (Enter Total of lines 67 to 75)	**$ 38,105,770**	**$ 49,181,384**
78	806 Exchange Gas	$ -	$ -
79	Purchased Gas Expenses		
80	807.1 Well Expenses - Purchased Gas		
81	807.2 Operation of Purchased Gas Measuring Stations		
82	807.3 Maintenance of Purchased Gas Measuring Stations		
83	807.4 Purchased Gas Calculations Expenses		
84	807.5 Other Purchased Gas Expenses		
85	TOTAL Purchased Gas Expenses (Enter Total of lines 80 thru 84)	**None**	**None**
86	808.1 Gas Withdrawn from Storage - Debit	$ 235,533	$ 500,317
87	(Less) 808.2 Gas Delivered to Storage - Credit	$ -	$ -
88	809.1 Withdrawals of Liquefied Natural Gas for Processing - Debit		
89	(Less) 809.2 Deliveries of Natural Gas for Processing - Credit		
90	(Less) Gas Used in Utility Operations - Credit		
91	810 Gas Used for Compressor Station Fuel - Credit		
92	811 Gas Used for Products Extraction - Credit		
93	812 Gas Used for Other Utility Operations - Credit	$ (25,871)	$ (25,069)
94	TOTAL Gas Used in Utility Operations - Credit (Lines 91 thru 93)	**$ (25,871)**	**$ (25,069)**
95	813 Other Gas Supply Expenses	$ 53,084	$ 22,289
96	TOTAL Other Gas Supply Exp (Lines 77, 78, 85, 86 thru 89, 94, 95)	**$ 38,368,516**	**$ 49,678,921**
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65 and 96)	**$ 38,368,516**	**$ 49,678,921**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2012

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
98	2. NATURAL GAS STORAGE, TERMINALING & PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering		
102	815 Maps and Records		
103	816 Wells Expenses		
104	817 Lines Expense		
105	818 Compressor Station Expenses		
106	819 Compressor Station Fuel and Power		
107	820 Measuring and Regulating Station Expenses		
108	821 Purification Expenses		
109	822 Exploration and Development		
110	823 Gas Losses		
111	824 Other Expenses		
112	825 Storage Well Royalties		
113	826 Rents		
114	TOTAL Operation (Enter Total of lines 101 thru 113)	**None**	**None**
115	Maintenance		
116	830 Maintenance Supervision and Engineering		
117	831 Maintenance of Structures and Improvements		
118	832 Maintenance of Reservoirs and Wells		
119	833 Maintenance of Lines		
120	834 Maintenance of Compressor Station Equipment		
121	835 Maintenance of Measuring and Regulating Station Equipment		
122	836 Maintenance of Purification Equipment		
123	837 Maintenance of Other Equipment		
124	TOTAL Maintenance (Enter Total of lines 116 thru 123)	**None**	**None**
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)	**None**	**None**
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering		
129	841 Operation Labor and Expenses		
130	842 Rents		
131	842.1 Fuel		
132	842.2 Power		
133	842.3 Gas Losses		
134	TOTAL Operation (Enter Total of lines 128 thru 133)	**None**	**None**
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering		
137	843.2 Maintenance of Structures and Improvements		
138	843.3 Maintenance of Gas Holders		
139	843.4 Maintenance of Purification Equipment		
140	843.5 Maintenance of Liquefaction Equipment		
141	843.6 Maintenance of Vaporizing Equipment		
142	843.7 Maintenance of Compressor Equipment		
143	843.8 Maintenance of Measuring and Regulating Equipment		
144	843.9 Maintenance of Other Equipment		
145	TOTAL Maintenance (Enter Total of lines 136 thru 144)	**None**	**None**
146	TOTAL Other Storage Expenses (Enter Total of lines 134 and 145)	**None**	**None**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering		
150	844.2 LNG Processing Terminal Labor and Expenses		
151	844.3 Liquefaction Processing Labor and Expenses		
152	844.4 Liquefaction Transportation Labor and Expenses		
153	844.5 Measuring and Regulation Labor and Expenses		
154	844.6 Compressor Station Labor and Expenses		
155	844.7 Communication System Expenses		
156	844.8 System Control and Load Dispatching		
157	845.1 Fuel		
158	845.2 Power		
159	845.3 Rents		
160	845.4 Demurrage Charges		
161	(Less) 845.5 Wharfage Receipts - Credit		
162	845.6 Processing Liquefied or Vaporized Gas by Others		
163	846.1 Gas Losses		
164	846.2 Other Expenses		
165	TOTAL Operation (Enter Total of lines 149 thru 164)	**None**	**None**
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering		
168	847.2 Maintenance of Structures and Improvements		
169	847.3 Maintenance of LNG Processing Terminal Equipment		
170	847.4 Maintenance of LNG Transportation Equipment		
171	847.5 Maintenance of Measuring and Regulating Equipment		
172	847.6 Maintenance of Compressor Station Equipment		
173	847.7 Maintenance of Communication Equipment		
174	847.8 Maintenance of Other Equipment		
175	TOTAL Maintenance (Enter Total of lines 167 thru 174)	**None**	**None**
176	TOTAL Liquefied Nat Gas Terminaling & Process Exp (Lines 165 & 175)	**None**	**None**
177	TOTAL Natural Gas Storage (Enter Total of lines 125, 146, and 176)	**None**	**None**
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering		
181	851 System Control and Load Dispatching		
182	852 Communication System Expenses		
183	853 Compressor Station Labor and Expenses		
184	854 Gas for Compressor Station Fuel		
185	855 Other Fuel and Power for Compressor Stations		
186	856 Mains Expenses		
187	857 Measuring and Regulating Station Expenses		
188	858 Transmission and Compression of Gas by Others		
189	859 Other Expenses		
190	860 Rents		
191	TOTAL Operation (Enter Total of lines 180 thru 190)	**None**	**None**
192	Maintenance		
193	861 Maintenance Supervision and Engineering		
194	862 Maintenance of Structures and Improvements		
195	863 Maintenance of Mains		
196	864 Maintenance of Compressor Station Equipment		
197	865 Maintenance of Measuring and Reg. Station Equipment		
198	866 Maintenance of Communication Equipment		
199	867 Maintenance of Other Equipment		
200	TOTAL Maintenance (Enter Total of lines 193 thru 199)	**None**	**None**
201	TOTAL Transmission Expenses (Enter Total of lines 191 and 200)	**None**	**None**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

LINE NO.	ACCOUNT (a)	CUURENT YEAR (b)	PREVIOUS YEAR (c)
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	$ 298,757	$ 259,735
205	871 Distribution Load Dispatching	$ 116,980	$ 115,655
206	872 Compressor Station Labor and Expenses	$ -	$ 39
207	873 Compressor Station Fuel and Power	$ -	$ -
208	874 Mains and Services Expenses	$ 994,877	$ 607,660
209	875 Measuring and Regulating Station Expenses - General	$ 250,699	$ 206,392
210	876 Measuring and Regulating Station Expenses - Industrial	$ 30,404	$ 28,965
211	877 Measuring & Regulating Station Exp - City Gate Check Station		
212	878 Meter and House Regulator Expenses	$ 339,828	$ 343,068
213	879 Customer Installations Expenses	$ 483,068	$ 439,635
214	880 Other Expenses	$ 1,088,039	$ 881,951
215	881 Rents	$ 21,279	$ 16,236
216	TOTAL Operation (Enter Total of lines 204 thru 215)	**$ 3,623,931**	**$ 2,899,336**
217	Maintenance		
218	885 Maintenance Supervision and Engineering	$ 22,846	$ 259
219	886 Maintenance of Structures and Improvements	$ 310	$ 11,486
220	887 Maintenance of Mains	$ 282,840	$ 208,724
221	888 Maintenance of Compressor Station Equipment	$ 1,455	$ 5,286
222	889 Maintenance of Meas. and Reg. Sta. Equip. - General	$ 96,662	$ 106,843
223	890 Maintenance of Meas. and Reg. Sta. Equip. - Industrial	$ 18,542	$ 34,695
224	891 Maint. of Meas. & Reg. Sta. Equip. - City Gate Check Station	$ -	
225	892 Maintenance of Services	$ 282,848	$ 171,240
226	893 Maintenance of Meters and House Regulators	$ 252,956	$ 294,465
227	894 Maintenance of Other Equipment	$ 139,225	$ 163,182
228	TOTAL Maintenance (Enter Total of lines 218 thru 227)	**$ 1,097,684**	**$ 996,180**
229	TOTAL Distribution Expenses (Enter Total of lines 216 and 228)	**$ 4,721,615**	**$ 3,895,516**
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	$ 13,531	$ 14,932
233	902 Meter Reading Expenses	$ 135,782	$ 126,925
234	903 Customer Records and Collection Expenses	$ 1,107,603	$ 988,282
235	904 Uncollectible Accounts	$ 693,641	$ 189,812
236	905 Miscellaneous Customer Accounts Expenses	$ 34,793	$ 5,908
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	**$ 1,985,350**	**$ 1,325,859**
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	$ -	$ -
241	908 Customer Assistance Expenses	$ 571,504	$ 577,611
242	909 Informational and Instructional Expenses	$ 28,236	$ 17,190
243	910 Miscellaneous Customer Service and Informational Expenses	$ -	$ 87
244	TOTAL Customer Service & Information Expenses (Lines 240 thru 243)	**$ 599,740**	**$ 594,888**
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	$ -	$ -
248	912 Demonstrating and Selling Expenses	$ -	$ -
249	913 Advertising Expenses	$ 2,591	$ 3,400
250	916 Miscellaneous Sales Expenses	$ -	$ -
251	TOTAL Sales Expenses (Enter Total of lines 247 thru 250)	**$ 2,591**	**$ 3,400**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES (Con't)

LINE NO.	ACCOUNT (a)	CURRENT YEAR (b)	PREVIOUS YEAR (c)
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	$ 1,541,917	$ 1,517,248
255	921 Office Supplies and Expenses	$ 1,269,742	$ 1,413,739
256	(Less) 922 Administrative Expenses Transferred - Cr.	$ (141,164)	$ (128,197)
257	923 Outside Services Employed	$ 208,394	$ 422,202
258	924 Property Insurance	$ 17,902	$ 20,373
259	925 Injuries and Damages	$ 280,335	$ 273,066
260	926 Employee Pensions and Benefits	$ 1,165,082	$ 1,455,688
261	927 Franchise Requirements	$ -	$ -
262	928 Regulatory Commission Expenses	$ 646	$ -
263	(Less) 929 Duplicate Charges - Cr.	$ -	$ -
264	930.1 General Advertising Expenses	$ 15,804	$ 23,307
265	930.2 Miscellaneous General Expenses	$ 156,046	$ 153,696
266	931 Rents	$ 364,542	$ 343,036
267	TOTAL Operation (Enter Total lines 254 thru 266)	**$ 4,879,246**	**$ 5,494,158**
268	Maintenance		
269	935 Maintenance of General Plant	$ 34,616	$ 21,929
270	TOTAL Administrative and General Exp (Total of lines 267 and 269)	**$ 4,913,862**	**$ 5,516,087**
271	TOTAL Gas O. & M. Exp (Lines 97,177,201,229,237,244,251 and 270)	**$ 50,591,674**	**$ 61,014,671**

STATE OF OREGON - ALLOCATED GAS OPERATION AND MAINTENANCE EXPENSES

LINE NO.	FUNCTIONAL CLASSIFICATIONS (a)	OPERATION (b)	MAINTENANCE (c)	TOTAL (d)
272	Production			
273	Manufactured Gas	$ -	$ -	$ -
274	Natural Gas:		$ -	$ -
275	Production and Gathering		$ -	$ -
276	Products Extraction			$ -
277	Exploration and Dev			$ -
278	TOTAL Natural Gas			$ -
279	Other Gas Supply Expenses	$ 38,368,516	$ -	$ 38,368,516
280	TOTAL Production	**$ 38,368,516**	**$ -**	**$ 38,368,516**
281	Underground Storage			
282	Other Storage			$ -
283	LNG Terminiling and Processing			$ -
284	Transmission Expenses			$ -
285	Distribution Expenses	$ 3,623,931	$ 1,097,684	$ 4,721,615
286	Customer Accounts Expenses	$ 1,985,350	$ -	$ 1,985,350
287	Customer Service and Informational Expenses	$ 599,740	$ -	$ 599,740
288	Sales Expenses	$ 2,591	$ -	$ 2,591
289	Admin and General Expenses	$ 4,879,246	$ 34,616	$ 4,913,862
290	TOTAL Gas O. & M. Expenses	**$ 49,459,374**	**$ 1,132,300**	**$ 50,591,674**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURALGAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - ALLOCATED DEPRECIATION, DEPLETION, AND AMORTIZATION OF GAS PLANT (Account 403, 404.1, 404.2, 404.3, 405)

(Except Amortization of Acquisition Adjustments)

Report the amounts of depreciation expense, depletion and amortization for the accounts indicated and classify according to the plant functional groups shown.

LINE NO.	FUNCTIONAL CLASSIFICATION (a)	DEPRECIATION EXPENSE (ACCOUNT 403) (b)	AMORTIZATION & DEPLETION OF PRODUCING NATURAL GAS LAND & LAND RIGHTS (ACCOUNT 404.1) (c)	AMORTIZATION OF UNDERGROUND STORAGE LAND & LAND RIGHTS (ACCOUNT 404.2) (d)	AMORTIZATION OF OTHER LIMITED-TERM GAS PLANT (ACCOUNT 404.3) (e)	AMORTIZATION OF OTHER GAS PLANT (ACCOUNT 405) (f)	TOTAL (g)
1	Intangible Plant			226,647			226,647
2	Production Plant, Manufactured Gas						-
3	Production and Gathering Plant, Natural Gas						-
4	Products Extraction Plant						-
5	Underground Gas Storage Plant						-
6	Other Storage Plant						-
7	Base load LNG Terminaling and Processing Plant						-
8	Transmission Plant	112,321					112,321
9	Distribution Plant	3,753,547					3,753,547
10	General Plant	250,801					250,801
11	Common Plant - Gas	[redacted]					-
12							
13							
14							
15							
16							
17							
18							
19	**TOTAL**	**4,116,669**	**-**	**226,647**	**-**	**-**	**4,343,316**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - ALLOCATED TAXES, OTHER THAN INCOME TAXES (Account 408.1)

LINE NO.	KIND OF TAX (a)	AMOUNT (b)
1	Property Tax	1,332,513
2	Payroll Taxes	436,735
3	Oregon PUC Regulatory Fee	201,516
4	Oregon Department of Energy Fee	61,277
5	City Franchise Taxes	2,627,136
6	Miscellaneous Taxes	19,897
	TOTAL (Must agree with page 1, line 11)	**4,679,074**

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NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2012

STATE OF OREGON - ALLOCATED CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE (Account 409.1)

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).

2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.

3. Current tax expense on this schedule must match the amount reported on page 1, line 12 of this report. Separately identify adjustments arising from revisions of prior year accruals.

4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	PARTICULARTS (Details) (a)			Amount (b)
1	Gas Operating Revenues			276,988,483
2	Operations and Maintenance Expenses			(198,442,941)
3	Taxes, Other than Income			(26,801,066)
4	State Income (Excise) Tax			28,425
5	Interest			(11,612,499)
6	Other Income			(665,349)
7	Federal Income Tax Depreciation			
8	Pre-1981			(414,553)
9	Post-1980			(42,253,335)
10	Other Additions (Subtractions) to Derive Taxable Income			
11	CIAC			1,423,741
12	Book depreciation included in O&M			859,066
13	Tax Gain (loss) on disposal of assets:			
14	Pre-1981 assets			1,424,333
15	Post-1980 assets			(228,628)
16	Vacation Accrual adjustment			(64,726)
17	Retiree Medical Accrual adjustment			(28,806)
18	Amort of loss on reacquired debt (4281)			249,054
19	SFAS No.87 pension plan accrual			741,470
20	SFAS No.87 accrual-SERP DO add back bk expense			209,284
21	SERP-perm difference piece			(807,276)
22	Bad Debt Adjustment			136,017
23	Charitable Contributions (5981.4261)			203,715
24	Permanent diff's			
25	50 % of business meals & entertainment			170,258
26	Penalties (5984)			2,187
27	Lobbying (5912.4264)			110,582
28	Tax exempt interest			42,336
29	Interest capitalized adj (IRS>books)			181,049
30	Customer Advances - 2520.000 to 2520.2991			20,902
31	CC&B Deduction			(2,495,149)
32	263A Adjustment - UNICAP			13,158
33	401K Dividends (MDUR)			(140,578)
34	Severance accrual adjustment			-
35	STIP accrual adjustment			(127,049)
36	Deferred Gas Costs			-
37	Royalty Income (15% of royalty income receipts)			(2,246)
38	Broken Meter interest charges			7,249
39	Installment sale - Seattle GO			1,285,184
40	Bremerton MGP expenses deferred			(148,407)
41	Eugene MGP expenses deferred			(97,054)
42	Federal Tax Net Income			(233,169)
43	Show Computation of Tax:			
44	Federal Tax Rate			35%
45	Estimated Federal Tax			(81,610)
46	Adjustments to Estimated Federal Tax			
47	Difference between 12/31/11 accrual and tax return			(1,133,371)
48	Audit adjustment			(35,649)
49	Provision for Current Federal Income Tax			(1,250,630)
50	Allocated to:	409.1	409.2	Total
51	Washington	(934,523)	1,952	(932,571)
52	Oregon	(318,693)	634	(318,059)
53	Total	**(1,253,216)**	**2,586**	**(1,250,630)**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - ALLOCATED CALCULATION OF CURRENT STATE INCOME (EXCISE) TAX EXPENSE (Account 409.1)

1. Report amounts used to derive current state income (excise) tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).

2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.

3. Current tax expense on this schedule must match the amount reported on page 1, line 13 of this report. Separately identify adjustments arising from revisions of prior year accruals.

4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	particularts (Details) (a)			Amount (b)
1	Gas Operating Revenues			276,988,483
2	Operations and Maintenance Expenses			(198,442,941)
3	Taxes, Other than Income			(26,801,066)
4	State Income (Excise) Tax			
5	Interest			(11,612,499)
6	Other Income			(665,349)
7	Federal Income Tax Depreciation			
8	Pre-1981			(414,553)
9	Post-1980			(43,862,956)
10	Other Additions (Subtractions) to Derive Taxable Income			
11	CIAC			1,423,741
12	Tax Gain (loss) on disposal of assets:			859,066
13	Tax Gain (loss) on disposal of assets:			
14	Pre-1981 assets			1,424,333
15	Post-1980 assets			(227,459)
16	Vacation Accrual adjustment			(64,726)
17	Retiree Medical Accrual adjustment			(28,806)
18	Amort of loss on reacquired debt (4281)			249,054
19	SFAS No.87 pension plan accrual			741,470
20	SFAS No.87 accrual-SERP DO add back bk expense			209,284
21	SERP-perm difference piece			(807,276)
22	Bad Debt Adjustment			136,017
23	Charitable Contributions (5981.4261)			203,715
24	Permanent diff's			-
25	50 % of business meals & entertainment			170,258
26	Penalties (5984)			2,187
27	Lobbying (5912.4264)			110,582
28	Tax exempt interest			42,336
29	Interest capitalized adj (IRS>books)			181,049
30	Customer Advances - 2520.000 to 2520.2991			20,902
31	CC&B Deduction			(2,495,149)
32	263A Adjustment - UNICAP			13,158
33	401K Dividends (MDUR)			(140,578)
34	Severance accrual adjustment			-
35	STIP accrual adjustment			(127,049)
36	Deferred Gas Costs			-
37	Royalty Income (15% of royalty income receipts)			(2,246)
38	Broken Meter interest charges			7,249
39	Installment sale - Seattle GO			1,285,184
40	Bremerton MGP expenses deferred			(148,407)
41	Eugene MGP expenses deferred			(97,054)
42	Federal Tax Net Income			(1,870,046)
43	Oregon Apportionment Rate			20%
44	State Tax Net Income			(374,009)
45	Show Computation of Tax:			
46	State Tax Rate			7.6%
47				(28,425)
48	Adjustments to Estimated Federal Tax			
49	Difference between 12/31/11 accrual and tax return			(57,514)
50	Audit adjustment			(996)
51	Provision for Current Federal Income Tax			(86,935)
52	Allocated to:	409.1	409.2	Total
53	Oregon	**(87,115)**	**180**	(86,935)

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2012

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. In the space provided:
   (a) Identify, by amount and classification, significant items for which deferred taxes are being provided.
   (b) Indicate insignificant amounts under OTHER.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Electric	0		
2				
3	Other			
4	TOTAL ELECTRIC			
5	Gas	24,456,261	2,721,781	-
6				
7	Other	-		
8	TOTAL GAS	24,456,261	2,721,781	-
9	Other (Specify)	-		
10	TOTAL (Account 190)	24,456,261	2,721,781	-
11	Classification of Totals			
12	Federal Income Tax	23,784,568	2,530,712	-
13	State Income Tax	671,693	191,069	-
14	Local Income Tax	-	-	-
15				
16	Amounts assigned to jurisdictions as follows:			
17	Federal Income Tax - Washington	See Below	1,887,152	-
18	Federal Income Tax - Oregon	See Below	643,560	-
19	State Income Tax - Oregon	671,693	191,069	-
20				
21				
22				

The federal balance in account 190 is allocated to Washington & Oregon on the basis of the Company's 3-factor formula which is used for the allocation of corporate level operating & maintenance expenses and interstate plant as follows:

	Beginning of Year	End of Year
Federal Income Tax related account Balance	23,784,568	26,662,464
	-	-
Balance to be allocated	23,784,568	26,662,464
Washington allocation factor	75.69%	75.47%
Washington Allocated balance	18,002,540	20,122,162
Oregon allocation factor	24.31%	24.53%
Oregon Allocated balance	5,782,028	6,540,302

NAME OF RESPONDENT **CASCADE NATURAL GAS COPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INCOME TAXES (Account 190) (continued)

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at	
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	DEBITS		CREDITS		End of Year	Line No.
		Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
						-	1
							2
							3
							4
-	-	Regulatory accounts related to FAS 158 and OR rate change adjustments	660,206			27,838,248	5
							6
						-	7
-	-		660,206		-	27,838,248	8
						-	9
-	-		660,206		-	27,838,248	10
							11
-	-		347,184			26,662,464	12
-	-		313,022			1,175,784	13
-	-		-		-	-	14
							15
							16
-	-		258,895		-	See Below	17
-	-		88,289		-	See Below	18
-	-		313,022		-	1,175,784	19
							20
							21
							22

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

ACCUMULATED DEFERRED INCOME TAXES - Accelerated Amortization Property (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.

2. In the space provided furnish explanations, including the following in colomnar order:

and dec (a) State each certification number with a brief description of property.

(b) Total and amortizable cost of such property.

(c) Date amortization for tax purposes commenced.

(d) "Normal" depreciation rate used in computing the deferred tax.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other			
6				
7				
8	TOTAL Electric (*Total of lines 3 thru 7)*	-	-	-
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other			
13				
14				
15	TOTAL Gas (*Total of lines 10 thru 14)*	-	-	-
16	Gas (Specify)			
17	TOTAL (Acct 281) *Total of 8, 15 & 16*	-	-	-
18	Classification of TOTAL			
19	Federal Income Tax	-	-	-
20	State Income Tax	-	-	-
21	Local Income Tax	-	-	-

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

ACCUMULATED DEFERRED INCOME TAXES - Accelerated Amortization Property (Account 281) (continued)

(e) Tax rate used originally defer amount and the tax rate used during the current year to amortize previous deferrals.
3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		DEBITS		CREDITS			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
-	-	-	-	-	-	-	8
							9
							10
							11
							12
							13
							14
-	-	-	-	-	-	-	15
						-	16
-	-	-	-	-	-	-	17
							18
-	-		-		-	-	19
-	-		-		-	-	20
-	-		-		-	-	21

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

ACCUMULATED DEFERRED INCOME TAXES-Other Property (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.
2. In the space provided furnish explanations, including the following in columnar order:
   (a) State the general method or methods of liberalized depreciation being used (sum-of-year digits, declining balance, etc.)
   (b) Estimated lives (i.e. useful life, guideline life, guideline class life, etc.)
   (c) Classes of plant to which each method is being applied and date method was adopted.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Credited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	-		
3	Gas	(70,046,021)	(7,684,666)	-
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(70,046,021)	(7,684,666)	-
6	Other (Specify)	-		
7				
8				
9	Total (Account 282) Lines 5 thru 8	(70,046,021)	(7,684,666)	-
10	Classification of Totals			
11	Federal Income Tax	(69,082,554)	(6,902,975)	-
12	State Income Tax	(963,467)	(781,691)	-
13	Local Income Tax	-	-	-

Amounts assigned to jurisdictions as follows:

Federal Income Tax - Washington	See Below	(5,147,549)	-
Federal Income Tax - Oregon	See Below	(1,755,426)	-
State Income Tax - Oregon	(963,467)	(781,691)	-

The federal balance in account 282 relating to utility plant for ratemaking is allocated to Washington & Oregon on the basis of the Company's Rate Base ratio, the remaining portion is allocated on the basis of the Company's ratio of utility plant in each state as follows:

	Beginning of Year	End of Year
Federal Income Tax Acct Balance Relating to utility plant for ratemaking	(72,320,671)	(79,224,881)
Washington allocation factor	76.13%	76.07%
Washington Allocated balance relating to utility plant for ratemaking	(55,057,727)	(60,266,367)
Oregon allocation factor	23.87%	23.93%
Oregon Allocated balance relating to utility plant for ratemaking	(17,262,944)	(18,958,514)
Remaining balance to be allocated on Utility Plant	3,238,117	4,100,970
Oregon allocation factor	22.93%	22.74%
Oregon allocation	742,500	932,561
Plus Oregon Allocation of utility plant for ratemaking related balance	(17,262,944)	(18,958,514)
Total Oregon Allocated Balance	(16,520,444)	(18,025,953)

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

ACCUMULATED DEFERRED INCOME TAXES-Other Property (Account 282) (continued)

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	DEBITS Account No.	DEBITS Amount	CREDITS Account No.	CREDITS Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
						-	2
-	-	254	861,618	182.3	(927,979)	(77,797,048)	3
						-	4
-	-		861,618		(927,979)	(77,797,048)	5
						-	6
							7
							8
-	-		861,618		(927,979)	(77,797,048)	9
							10
-	-	254	861,618	182.3	-	(75,123,911)	11
-	-	254	-	182.3	(927,979)	(2,673,137)	12
-	-		-		-	-	13
-	-		642,509		-	See Below	
-	-		219,109		-	See Below	
-	-		-		(927,979)	(2,673,137)	

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

STATE OF OREGON - ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. In the space provided below include amounts relating to insignificant items under Other.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited Account 411.1 (d)
1	Account 283			
2	Electric			
3	Gas	(27,479,312)	(3,853,071)	-
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(27,479,312)	(3,853,071)	-
6	Other (Specify)	-		
7				
8				
9	Total (Account 283) Lines 5 thru 8	(27,479,312)	(3,853,071)	-
10	Classification of Totals			
11	Federal Income Tax	(26,307,341)	(3,574,506)	-
12	State Income Tax	(1,171,971)	(278,565)	-
13	Local Income Tax	-	-	-

Amounts assigned to jurisdictions as follows:

Federal Income Tax - Washington	See below	(2,665,509)	-
Federal Income Tax - Oregon	See below	(908,997)	-
State Income Tax - Oregon	(1,171,971)	(278,565)	-

The federal balance in account 283 relating to debt refinancing costs is allocated to Washington & Oregon on the basis of the Company's Rate Base ratio, the remaining portion is allocated on the basis of the 3-factor formula which is used for the allocation of corporate level operating & maintenance expenses and interstate plant. The allocation in each state is as follows:

	Beginning of Year	End of Year
Federal Income Tax Acct Balance Relating to Debt Refinancing	(450,939)	(350,520)
Washington allocation factor	76.13%	76.07%
Washington Allocated balance relating to Debt Refinancing	(343,300)	(266,641)
Oregon allocation factor	23.87%	23.93%
Oregon Allocated balance relating to Debt Refinancing	(107,639)	(83,879)
Remaining balance to be allocated on 3-factor	(25,856,402)	(29,884,773)
Oregon allocation factor	24.31%	24.53%
Oregon allocation	(6,285,691)	(7,330,735)
Plus Oregon Allocation of Debt refinancing related balance	(107,639)	(83,879)
Total Oregon Allocated Balance	(6,393,330)	(7,414,614)

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

STATE OF OREGON - ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283) (continued)

3. Beginning balance may be omitted if not readily available. Report gas utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at	
Amounts	Amounts	DEBITS		CREDITS		End	
Debited	Credited	Account No.	Amount	Account No.	Amount	of Year	Line
Account 410.2	Account 411.2						No.
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
[redacted]							1
							2
-	-	Regulatory accounts related to deferred tax effect of OR State Tax Rate increase	15,500	Regulatory accounts related to FAS 158 adjustment	(659,869)	(31,976,752)	3
						-	4
-	-		15,500		(659,869)	(31,976,752)	5
						-	6
							7
							8
-	-		15,500		(659,869)	(31,976,752)	9
[redacted]							10
-	-		(6,299)		(347,147)	(30,235,293)	11
-	-		21,799		(312,722)	(1,741,459)	12
-	-		-		-	-	13
-	-		(4,697)		(258,868)	See below	
-	-		(1,602)		(88,279)	See below	
-	-		21,799		(312,722)	(1,741,459)	

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2012

STATE OF OREGON - ALLOCATED ACCUMULATED DEFERRED INVESTMENT TAX CREDIT (Account 255)

Report below information applicable to Account 255. Explain by footnote any correction or adjustment to the account balance shown in column (g). Include in column (i) the average period over which the tax credit is amortized.

Line No.	Account Subdivision	Balance at Beginning of Year	Deferred For Year		Allocations to Current Year's Income		Adjustments	Balance at End of Year	Average period of Allocation to Income
			Account No	Amount	Account No	Amount			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas utility								
2	3%								
3	4%	NOT			411.4	-		NOT	31 Years
4	7%				411.4	-			31 Years
5	10%	ALLOCATED			411.4	(4,372)		ALLOCATED	23 Years
6	Total	0		0		(4,372)			
7	Other (list separately and show 3%, 4%, 7&, 10% and TOTAL)								
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									

NOTES

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT		YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)		Dec. 31, 2012

STATE OF OREGON - SITUS UTILITY PLANT

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specifiy) (e)	Other (Specifiy) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (classified)	155,508,406		155,508,406			
4	Property under capital leases	-					
5	Plant purchased or sold	-					
6	Completed construction not classified	-					
7	Experimental plant unclassified	-					
8	TOTAL (Enter Total of lines 3 thru 7)	155,508,406	-	155,508,406	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	2,198,929		2,198,929			
12	Acquisition Adjustments	-					
13	Total Utility Plant (Enter Total of lines 8 thru 12)	157,707,335	-	157,707,335	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(74,956,224)		(74,956,224)			
15	Net Utility Plant (Line 13 less 14)	82,751,111	-	82,751,111	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(74,956,224)		(74,956,224)			
19	Amort. and Depl. of producing natural gas land and land rights	-		-			
20	Amort. of underground storage land and land rights	-		-			
21	Amort. of other utility plant	-		-			
22	Total In-Service (Total of lines 18 thru 21)	(74,956,224)	-	(74,956,224)	-		-
23	Leased to Others						
24	Depreciation	-		-			
25	Amortization and depletion	-		-			
26	Total leased to others (Total of lines 24 and 25)	-	-	-	-		-
27	Held for Future Use						
28	Depreciation	-		-			
29	Amortization	-		-			
30	Total Held for Future Use(Total of lines 28 & 29)	-	-	-	-		-
31	Abandoment of Leases (Natural Gas)						
32	Amort. Of Plant Acquisitions Adj.	-		-			
33	TOTAL Accumulated Provisions (should agree with line 14)(lines 22,26, 30, 31 & 32)	(74,956,224)	-	(74,956,224)	-		-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2012

STATE OF OREGON - SITUS GAS PLANT IN SERVICE

1. Report below the original cost of gas plant in service according to the prescribed accounts.

2. In addition to Account 101, *Gas Plant In Service (Classified)*, this page and the next include Account 102, *Gas Plant Purchased or Sold*; Account 103, *Experimental Gas Plant Unclassified*; and Account 106, *Completed Construction not Classified*.

3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.

4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.

5. Classify Account 106 according to prescribed accounts on an estimated basis if necessary, and include entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in column (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at the end of year. **(Continue on page 25)**

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
1		1. Intangible Plant						
2	301	Organization						
3	302	Franchises and Consents	73,667	-	-	-	-	73,667
4	303	Miscellaneous Intangible Plant	-	-	-	-	-	-
5		TOTAL Intangible Plant	73,667	-	-	-	-	73,667
6		2. Production Plant						
7		Natural Gas Production & Gathering Plant						
8	325.1	Producing Lands	-					-
9	325.2	Producing leaseholds	-					-
10	325.3	Gas Rights	-					-
11	325.4	Rights-of-Way	-					-
12	325.5	Other Land and Land Rights	-					-
13	326	Gas Well Structures	-					-
14	327	Field Compressor Station Structures	-					-
15	328	Field Measuring and Regulating Station Structures	-					-
16	329	Other Structures	-					-
17	330	Producing Gas Wells- Well Construction	-					-
18	331	Producing Gas Wells- Well Equipment	-					-
19	332	Field Lines	-					-
20	333	Field Compressor Station Equipment	-					-
21	334	Field Measuring and Regulating Station Equipment	-					-
22	335	Drilling and Cleaning Equipment	-					-
23	336	Purification Equipment	-					-
24	337	Other Equipment	-					-
25	338	Unsuccessful Exploration & Development Costs	-					-
26		TOTAL Production & Gathering Plant	-	-	-	-	-	-
27		Products Extraction Plant						
28	340	Land and Land Rights	-					-
29	341	Structures and Improvements	-					-
30	342	Extraction and Refining Equipmnet	-					-
31	343	Pipe Lines	-					-
32	344	Extracted Products Storage Equipment	-					-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - SITUS GAS PLANT IN SERVICE (Con't)

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initally recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing sub-account classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
		2. Production Plant (Con't) Products Extraction Plant (Con't)						
33	345	Compressor Equipment	-					-
34	346	Gas Measuring and Regulating Equipment	-					-
35	347	Other Equipment	-					-
36		TOTAL Products Extraction Plant	-	-	-	-	-	-
37		TOTAL Nat. Gas Production Plant	-	-	-	-	-	-
38		Mfd. Gas Production Plant (*Submit Suppl. Statement*)						-
39		TOTAL Production Plant	-	-	-	-	-	-
40		3. Natural Gas Storage & Processing Plant						
41		Underground Storage						
42	350.1	Land	-					-
43	350.2	Rights-of-Way	-					-
44	351	Structures and Improvements	-					-
45	352	Wells	-					-
46	352.1	Storage Leaseholds and Rights	-					-
47	352.2	Reservois	-					-
48	352.3	Non-Recoverable Natural Gas	-					-
49	353	Lines	-					-
50	354	Compressor Station Equipment	-					-
51	355	Measuring and Regulating Equipment	-					-
52	356	Purification Equipment	-					-
53	357	Other Equipment	-					-
54		TOTAL Underground Storage Plant	-	-	-	-	-	-
55		Other Storage Plant						
56	360	Land and Land Rights	-					
57	361	Structures and improvements	-					
58	362	Gas Holders	-					
59	363	Purification Equipment	-					
60	363.1	Liquefaction Equipment	-					
61	363.2	Vaporizing Equipment	-					-
62	363.3	Compressor Equipment	-					-
63	363.4	Measuring and Regulating Equipment	-					-
64	363.5	Other Equipment	-					-
65		TOTAL Other Storage Plant	-	-	-	-	-	-

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (Mo, Da, Yr)	YEAR OF REPORT Dec. 31, 2012

STATE OF OREGON - SITUS GAS PLANT IN SERVICE (Con't)

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
66		Base Load Liquefied Natural Gas Terminating and Processing Plant						
67	364.1	Land and Land Rights	-					-
68	364.2	Structures and Improvements	-					-
69	364.3	LNG Processing Terminal Equipment	-					-
70	364.4	LNG Transportation Equipment	-					-
71	364.5	Measuring and Regulating Equipment	-					-
72	364.6	Compressor Station Equipment	-					-
73	364.7	Communications Equipment	-					-
74	364.8	Other Equipment	-					-
75		TOTAL Base Load Liequefied Natural	-	-	-	-	-	-
76		Gas, Terminaling & Processing Plant	-					-
77		TOTAL Nat. Gas Storage & Proc. Plant	-	-	-	-	-	-
78		4. Transmission Plant						
79	365.1	Land and Land Rights	13,131	-	-	-	-	13,131
80	365.2	Rights of Way	7,693	-	-	-	-	7,693
81	366	Structures and Improvements	-					-
82	367	Mains	5,818,920	-	-	-	-	5,818,920
83	368	Compressor Station Equipment	-					-
84	369	Measuring and Regulating Station Equipment	48,548	-	-	-	-	48,548
85	370	Communications Equipment	-					-
86	371	Other Equipment	-					-
87		TOTAL Transmission Plant	5,888,292	-	-	-	-	5,888,292
88		5. Distribution Plant						
89	374	Land and Land Rights	170,902	53,728	-	-	-	224,630
90	375	Structures and Improvements	326,674	-	-	-	-	326,674
91	376	Mains	69,807,666	617,529	(46,899)	(9,680)	-	70,368,616
92	377	Compressor Station Equipment	-					-
93	378	Measuring and Regulating Equipment - General	6,932,652	552,778	(13,229)	-	-	7,472,201
94	379	Measuring and Regulating Equipment - City Gate	-					-
95	380	Services	38,670,890	809,557	(34,437)	-	-	39,446,010
96	381	Meters	11,614,684	166,713	(50,994)	(77,676)	-	11,652,727
97	382	Meter Installations	7,940,579	35,285	(4,579)	-	-	7,971,285
98	383	House Regulators	2,357,894	99,831	(32,176)	(15,570)	-	2,409,979
99	384	House Regulator Installations	-					-
100	385	Industrial Measuring and Regulating Station Equipment	1,426,392	35,357	(3,447)	-	-	1,458,302
101	386	Other Property on Customers' Premises	-					-
102	387	Other Equipment	-					-
102.a	388	ARO - Distribution	4,425	-	-	-	-	4,425
103		TOTAL Distribution Plant	139,252,758	2,370,778	(185,761)	(102,926)	-	141,334,849

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

STATE OF OREGON - SITUS GAS PLANT IN SERVICE (Con't)

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
104		6. General Plant						
105	389	Land and Land Rights	316,796	-	-	-	-	316,796
106	390	Structures and Improvements	3,159,178	4,225	-	-	-	3,163,403
107	391	Office Furniture and Equipment	120,987	59,092	(1,367)	-	9,059	187,771
108	392	Transportation Equipment	1,718,187	486,704	(46,547)	79,579	-	2,237,923
109	393	Stores Equipment	1,171	-	-	-	-	1,171
110	394	Tools, Shop and Garage Equipment	739,372	103,550	(7,651)	-	-	835,271
111	395	Laboratory Equipment	-	-	-	-	-	-
112	396	Power Operated Equipment	490,665	350,962	(205,124)	(29,455)	-	607,048
113	397	Communication Equipment	794,066	55,940	(5,505)	-	-	844,501
114	398	Miscellaneous Equipment	13,164	4,550	-	-	-	17,714
115		SUBTOTAL	7,353,586	1,065,023	(266,194)	50,124	9,059	8,211,598
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	7,353,586	1,065,023	(266,194)	50,124	9,059	8,211,598
118		TOTAL (Accounts 101 and 106)	152,568,303	3,435,801	(451,955)	(52,802)	9,059	155,508,406
119		Gas Plant Purchased (*See Instr. 8*)	-					-
120		(less) Gas Plant Sold (*See Instr. 8*)	-					-
121		Experimental Gas Plant Unclassified	-					-
122		TOTAL Gas Plant in Service	152,568,303	3,435,801	(451,955)	(52,802)	9,059	155,508,406

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

STATE OF OREGON - SITUS GAS PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $100,000 or more. Other items of property held or future use may be grouped provided that the number of properties so grouped is indicated.
2. For property having an original cost of $100,000 or more previously used in utility operations, now held for future use, give, in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in this Acct. (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Natural gas lands, leaseholds, and gas rights held for future utility use.			None
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46	T O T A L S -	0	0	0

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2012

STATE OF OREGON - SITUS CONSTRUCTION WORK IN PROGRESS - GAS (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects may be grouped.

Line No.	Description of Projects (a)	Construction Work In Progress - GAS (Account 107) (b)	Estimated Additional Cost of Project (c)
1	Bend Pipe Replacement Project	1,172,112	
2			
3			
4			
5			
6	Installation of mains, service lines, measuring and regulating stations,	1,026,817	
7	meter sets and telemetering, etc.		
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43	T O T A L -	2,198,929	0

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

STATE OF OREGON - SITUS ACCUMULATED PROVISION FOR DEPRECIATION OF GAS UTILITY PLANT (account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for gas plant in service, pages 24-27, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to various reserve functional classifications make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4 Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During the Year

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant In Service (c)	Gas Plant Held For Future Use (d)	Gas Plant Leased to Others (e)
1	Balance Beginning of Year	(71,274,093)	(71,274,093)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(3,952,959)	(3,952,959)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(185,035)	(185,035)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	(198)	(198)		
7.02	Other	-			
8		-			
9	TOTAL Depreciation Provisions for Year (*Enter total of lines 3 thru 8*)	(4,138,192)	(4,138,192)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	368,785	368,785		
12	Cost of Removal	165,767	165,767		
13	Salvage (credits)	(127,725)	(127,725)		
14	TOTAL Net Charges for Plant Retired (*enter Total of Lines 11 thru 13*)	406,827	406,827		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	(16,327)	(16,327)		
15.02	Adjustment Due to Change in Allocation Rate	65,561	65,561		
16					
17	Balance End of Year (*Enter Total of Lines 1, 9, 14, 15, & 16*)	(74,956,224)	(74,956,224)		
	Section B. Balances at End of Year According to Functional Classifications				
18	Production - Manufactured Gas	-	-		
19	Production and Gathering - Natural Gas	-	-		
20	Products Extraction - Natural Gas	-	-		
21	Underground Gas Storage	-	-		
22	Other Storage Plant	-	-		
23	Base Load LNG Terminaling and Proc. Plant	-	-		
24	Transmission	(2,628,549)	(2,628,549)		
25	Distribution	(68,631,653)	(68,631,653)		
26	General	(3,639,879)	(3,639,879)		
26.01	Intangible	(73,667)	(73,667)		
26.02	Retirement Work-In-Progress	17,524	17,524		
27	TOTAL (*Enter Total of Lines 18 thru 26*)	(74,956,224)	(74,956,224)		

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT		YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)		Dec. 31, 2012

STATE OF OREGON - ALLOCATED

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specifiy) (e)	Other (Specifiy) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (classified)	8,844,810		8,844,810			
4	Property Under Capital Leases	-					
5	Plant Purchased or Sold	-					
6	Completed Construction not Classified	-					
7	Experimental Plant Unclassified	-					
8	TOTAL (*Enter Total of lines 3 thru 7*)	8,844,810	-	8,844,810	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	1,784,104		1,784,104			
12	Acquisition Adjustments	-					
13	Total Utility Plant (*Lines 8 thru 12*)	10,628,914	-	10,628,914	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(3,779,533)		(3,779,533)			
15	Net Utility Plant (Line 13 less 14)	6,849,381	-	6,849,381	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(3,329,019)		(3,329,019)			
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights	-		-			
20	Amort. of Underground Storage Land and Land Rights	-		-			
21	Amort. of Other Utility Plant	(450,514)		(450,514)			
22	Total In-Service (*Lines 18 thru 21*)	(3,779,533)	-	(3,779,533)	-		-
23	Leased to Others						
24	Depreciation	-		-			
25	Amortization and Depletion	-		-			
26	Total Leased to Others (*Lines 24 and 25*)	-	-	-	-		-
27	Held for Future Use						
28	Depreciation	-		-			
29	Amortization and Depletion	-		-			
30	Total Leased to Others (*Lines 28 and 29*)	-	-	-	-		-
31	Abandoment of Leases (Natural Gas)						
32	Amort. Of Plant Acquisitions Adj.	-		-			
33	TOTAL Accumulated Provisions (should agree with line 14) (*lines 22, 26, 30, 31 & 32*)	(3,779,533)	-	(3,779,533)	-		-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2012

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE

1. Report below the original cost of gas plant in service according to the prescribed accounts.

2. In addition to Account 101, *Gas Plant In Service (Classified)*, this page and the next include Account 102, *Gas Plant Purchased or Sold*; Account 103, *Experimental Gas Plant Unclassified;* and Account 106, *Completed Construction not Classified*.

3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.

4. Enclose in Parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.

5. Classify Account 106 according to prescribed accounts on an estimated basis if necessary, and include entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in column (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at the end of year. **(Continue on page 25)**

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
1		1. Intangible Plant						
2	301	Organization	37,484	-	-	(182)	-	37,302
3	302	Franchises and Consents	-	-	-	-	-	-
4	303	Miscellaneous Intangible Plant	2,986,858	1,158,207	-	23,726	-	4,168,791
5		TOTAL Intangible Plant	3,024,342	1,158,207	-	23,544	-	4,206,093
6		2. Production Plant						
7		Natural Gas Production & Gathering Plant						
8	325.1	Producing Lands	-					-
9	325.2	Producing Leaseholds	-					-
10	325.3	Gas Rights	-					-
11	325.4	Rights-of-Way	-					-
12	325.5	Other ILand and Land Rights	-					-
13	326	Gas Well Structures	-					-
14	327	Field Compressor Station Structures	-					-
15	328	Field Measuring and Regulating Station Structures	-					-
16	329	Other Structures	-					-
17	330	Producing Gas Wells- Well Construction	-					-
18	331	Producing Gas Wells- Well Equipment	-					-
19	332	Field Lines	-					-
20	333	Field Compressor Station Equipment	-					-
21	334	Field Eeasuring and Regulating Station Equipment	-					-
22	335	Drilling and Cleaning Equipment	-					-
23	336	Purification Equipment	-					-
24	337	Other Equipment	-					-
25	338	Unsuccessful Exploration & Development Costs	-					-
26		TOTAL Production & Gathering Plant	-	-	-	-	-	-
27		Products Extraction Plant						
28	340	Land and Land Rights	-					-
29	341	Structures and Improvements	-					-
30	342	Extraction and Refining Equipmnet	-					-
31	343	Pipe Lines	-					-
32	344	Extracted Products Storage Equipment	-					-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2012

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (Con't)

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initally recorded in Account 102. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing sub-account classification of such plant conforming to the requirements of these pages.

8. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchaser, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date of such filing.

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
		2. Production Plant (Con't) Products Extraction Plant (Con't)						
33	345	Compressor Equipment	-					-
34	346	Gas Measuring and Regulating Equipment	-					-
35	347	Other Equipment	-					-
36		TOTAL Products Extraction Plant	-	-	-	-	-	-
37		TOTAL Nat. Gas Production Plant	-	-	-	-	-	-
38		Mfd. Gas Production Plant (*Submit Suppl. Statement*)						-
39		TOTAL Production Plant	-	-	-	-	-	-
40		3. Natural Gas Storage & Processing Plant						
41		Underground Storage Plant						
42	350.1	Land	-					-
43	350.2	Rights-of-Way	-					-
44	351	Structures and Improvements	-					-
45	352	Wells	-					-
46	352.1	Storage Leaseholds and Rights	-					-
47	352.2	Reservoirs	-					-
48	352.3	Non-Recoverable Natural Gas	-					-
49	353	Lines	-					-
50	354	Compressor Station Equipment	-					-
51	355	Measuring and Regulating Equipment	-					-
52	356	Purification Equipment	-					-
53	357	Other Equipment	-					-
54		TOTAL Underground Storage Plant	-	-	-	-	-	-
55		Other Storage Plant						
56	360	Land and Land Rights	-					
57	361	Structures and Improvements	-					
58	362	Gas Holders	-					
59	363	Purification Equipment	-					
60	363.1	Liquefaction Equipment	-					
61	363.2	Vaporizing Equipment	-					-
62	363.3	Compressor Equipment	-					-
63	363.4	Measuring and Regulating Equipment	-					-
64	363.5	Other Equipment	-					-
65		TOTAL Other Storage Plant	-	-	-	-	-	-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2012

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (Con't)

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
66		Base Load Liquefied Natural Gas Terminating and Processing Plant						
67	364.1	Land and Land Rights	-					-
68	364.2	Structures and Improvements	-					-
69	364.3	LNG Processing Terminal Equipment	-					-
70	364.4	LNG Transportation Equipment	-					-
71	364.5	Measuring and Regulating Equipment	-					-
72	364.6	Compressor Station Equipment	-					-
73	364.7	Communications Equipment	-					-
74	364.8	Other Equipment	-					-
75		TOTAL Base Load Liequefied Natural	-	-	-	-	-	-
76		Gas, Terminaling & Processing Plant	-					-
77		Total Nat. Gas Storage & Proc. Plant	-	-	-	-	-	-
78		4. Transmission Plant						
79	365.1	Land and Land Rights	-					-
80	365.2	Rights-of-Way	-					-
81	366	Structures and Improvements	-					-
82	367	Mains	-					-
83	368	Compressor Station Equipment	-					-
84	369	Measuring and Regulating Station Equipment	-					-
85	370	Communication Equipment	-					-
86	371	Other Equipment	-					-
87		TOTAL Transmission Plant	-	-	-	-	-	-
88		5. Distribution Plant						
89	374	Land and Land Rights	23,393	-	-	(114)	-	23,279
90	375	Structures and Improvements	98,389	-	-	(468)	-	97,921
91	376	Mains	-					-
92	377	Compressor Station Equipment	-					-
93	378	Measuring and Regulating Equipment - General	-					-
94	379	Measuring and Regulating Equipment - City Gate	-					-
95	380	Services	-					-
96	381	Meters	-					-
97	382	Meter Installations	-					-
98	383	House Regulators	-					-
99	384	House Regulator Installations	-					-
100	385	Industrial Measuring and Regulating Station Equipment	-					-
101	386	Other Property on Customers' Premises	-					-
102	387	Other Equipment	-					-
102.a	388	ARO - Distribution	-					-
103		TOTAL Distribution Plant	121,782	-	-	(582)	-	121,200

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

STATE OF OREGON - ALLOCATED GAS PLANT IN SERVICE (Con't)

LINE NO.		ACCOUNT (a)	BALANCE AT BEG. OF YEAR (b)	ADDITIONS (c)	RETIREMENTS (d)	ADJUSTMENTS (e)	TRANSFERS (f)	BALANCE AT END OF YEAR (g)
104		6. General Plant						
105	389	Land and Land Rights	2,090	-	-	1,317	156,545	159,952
106	390	Structures and Improvements	145,063	(1,263)	-	13,087	1,212,475	1,369,362
107	391	Office Furniture and Equipment	2,261,511	9,788	(167,428)	37,222	75,425	2,216,518
108	392	Transportation Equipment	262,190	24,488	-	(42,237)	-	244,441
109	393	Stores Equipment	14,727	-	-	(4,035)	-	10,692
110	394	Tools, Shop, and Garage Equipment	255,890	32,045	(1,302)	(356)	-	286,277
111	395	Laboratory Equipment	27,082	-	-	(131)	-	26,951
112	396	Power Operated Equipment	27,086	6,573	-	(19,464)	-	14,195
113	397	Communication Equipment	148,090	3,276	-	30,582	-	181,948
114	398	Miscellaneous Equipment	39	7,143	-	(1)	-	7,181
115		SUBTOTAL	3,143,768	82,050	(168,730)	15,984	1,444,445	4,517,517
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	3,143,768	82,050	(168,730)	15,984	1,444,445	4,517,517
118		TOTAL (Accounts 101 and 106)	6,289,892	1,240,257	(168,730)	38,946	1,444,445	8,844,810
119		Gas Plant Purchased (*See Instr. 8*)	-					-
120		(less) Gas Plant Sold (*See Instr. 8*)	-					-
121		Experimental Gas Plant Unclassified	-					-
122		TOTAL Gas Plant in Service	6,289,892	1,240,257	(168,730)	38,946	1,444,445	8,844,810

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2012

STATE OF OREGON - ALLOCATED GAS PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $100,000 or more. Other items of property held or future use may be grouped provided that the number of properties so grouped is indicated.
2. For property having an original cost of $100,000 or more previously used in utility operations, now held for future use, give, in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location of Property (a)	Date Originally Included in this Account (b)	Date Expected to be Used in Utility Service (c)	Balance End of Year (d)
1	Natural gas lands, leaseholds, and gas rights held for future utility use.			None
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46	T O T A L S -	0	0	0

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

STATE OF OREGON - ALLOCATED CONSTRUCTION WORK IN PROGRESS - GAS (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107).
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstration (see Account 107 of the Uniform System of Accounts).
3. Minor projects may be grouped.

Line No.	Description of Projects (a)	Construction Work In Progress (Acct 107) (b)	Estimated Additional Cost of Project (c)
1	Installation of mains, service lines, measuring and regulating stations,		
2	meter sets and telemetering, etc.		
3	Other general plant work in progress expenditures	1,784,104	
4			
5			
6			
7			
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43	T O T A L -	1,784,104	0

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2012

STATE OF OREGON - ALLOCATED ACCUMULATED PROVISION FOR DEPRECIATION OF GAS UTILITY PLANT (account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for gas plant in service, pages 32-35, column (d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to various reserve functional classifications make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During the Year

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant In Service (c)	Gas Plant Held For Future Use (d)	Gas Plant Leased to Others (e)
1	Balance Beginning of Year	(3,348,409)	(3,348,409)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(163,710)	(163,710)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(23,804)	(23,804)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	-			
7.02	Other	-			
8		-			
9	*8*)	(187,514)	(187,514)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	254,022	254,022		
12	Cost of Removal	872	872		
13	Salvage (credits)	(13,643)	(13,643)		
14	*13*)	241,251	241,251		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	(832)	(832)		
15.02	Adjustment Due to Change in Allocation Rate	(33,515)	(33,515)		
16					
17	Balance End of Year (*Enter Total of Lines 1, 9, 14, 15, & 16*)	(3,329,019)	(3,329,019)		

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant In Service (c)	Gas Plant Held For Future Use (d)	Gas Plant Leased to Others (e)
18	Production - Manufactured Gas	-	-		
19	Production and Gathering - Natural Gas	-	-		
20	Products Extraction - Natural Gas	-	-		
21	Underground Gas Storage	-	-		
22	Other Storage Plant	-	-		
23	Base Load LNG Terminaling and Proc. Plant	-	-		
24	Transmission	2,628,549	2,628,549		
25	Distribution	(9,671,114)	(9,671,114)		
26	General	3,639,879	3,639,879		
26.01	Intangible	73,667	73,667		
26.02	Retirement Work-In-Progress	0	0		
27	TOTAL (*Total of Lines 18 thru 26*)	(3,329,019)	(3,329,019)		

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2012

STATE OF OREGON - GAS STORED (ACCOUNT 117, 164.1, 164.2 AND 164.3)

1. Report below the information called for concerning inventories of gas stored.
2. The Uniform System of Accounts provides that inventory cost records be maintained on a consolidated basis for all storage projects with separate records showing the Mcf of inputs and withdrawals and balance for each project, except under certain specified circumstances. If the respondent's inventory cost records are not maintained on a consolidated basis for all storage projects, furnish an explanation of the accounting followed and reason for any deviation from the general basis provided by the Uniform System of Accounts. Separate schedules on this schedule form should be furnished for each group of storage projects for which separate inventory cost records are maintained.
3. If during the year adjustment was made of the stored gas inventory, such as to correct for cumulative inaccuracies of gas measurements, furnish an explanation of the reason for the adjustment, the Mcf and dollar amount of adjustment and account charged or credited.
4. Give a concise statement of the facts and the accounting performed with respect to any encroachment of withdrawals during the year, or restoration of previous encroachment, upon native gas constituting the "gas cushion" of any storage reservoir.
5. If the respondent uses a "base stock" in connection with its inventory accounting, give a concise statement of the basis of establishing such "base stock", the inventory basis, and the accounting performed with respect to any encroachment of withdrawals upon "base stock", or restoration of previous encroachment including brief particulars of any such accounting during the year.
6. If respondent has provided accumulated provision for such stored gas which may not eventually be fully recovered from any storage project, furnish a statement showing: (a) date of Commission authorization of such accumulated provision, (b) explanation of circumstances requiring such provision, (c) basis of provision and factors of calculation, (d) estimated ultimate accumulated provision accumulation, (e) a summary showing balance of accumulated provision and entires during year.
7. Pressure base of gas volumes reported in this schedule is 14.73 psia at 60" F.

Line No.	Description	NonCurrent (Acct 117) (a)	Current (Acct 164.1) (b)	LNG (Acct 164.2) (c)	LNG (Acct 164.3) (d)	Total (e)
1	Balance, beginning of year	Not allocated		Not allocated		Not allocated
2	Gas delivered to storage					
3	(contract account)		0	0		0
4	Gas withdrawn from storage					
5	(contra account)			$ -		$ -
6	Other debits or credits					
7	(explain)					
8						
9						
10						
11						
12	Balance, end of year	Not allocated		Not allocated		Not allocated
13	Mcf					
14	Amount per Mcf					

Line No.	Description	Total
15	State basis of segregation of inventory between current and noncurrent portions:	
16		
17	Gas delivered to storage:	
18	Mcf	Not allocated
19	Amount per Mcf	Not allocated
20	Cost basis of gas delivered to storage:	
21	Specify: Own production (give production area, see	
22	uniform system of accounts); average system purchases;	
23	specific purchases (state which purchases).	
24	Does cost of gas delivered to storage include any expenses	
25	for use of respondent's transmission, storage, or other	
26	facilities? If so, give particulars and date of Commission	
27	approval of the accounting.	
28		
29	Gas withdrawn from storage:	
30	Mcf	0
31	Amount per Mcf	-
32	Cost basis of withdrawals:	
33	Specify: average cost, lifo, fifo, (Explain any change in	F i f o
34	inventory basis during year and give date of Commission	
35	approval of the change or approval of an inventory basis	
36	different from that referred to in uniform system of accounts.)	
37		
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NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OR OREGON - GAS PURCHASES (Accounts 800, 801, 802, 803, 804.1 and 805)

1. Report particulars of gas purchases during the year in the manner prescribed below. (Code numbers to be used in reporting for Columns (d), (e) and (f) will be supplied by the Commission.)

2. Provide subheadings and totals for prescribed accounts as follows:

800 Natural Gas Well Head Purchases
801 Natural Gas Field Line Purchases
802 Natural Gas Gasoline Plant Outlet Purchases
803 Natural Gas Transmission Line Purchases
804 Natural Gas City Gate Purchases
804.1 Liquefied Natural Gas Purchases
805 Other Gas Purchases

Purchases are to be reported in account number sequence; e.g., all purchases charged to Account 800, followed by charges to Account 801, etc. Under each account number, purchases should be reported by states in alphabetical order. Totals are to be shown for each account in Columns (k) and (l) and should agree with the books of account, or any differences reconciled.

3. Purchases may be reported by gas purchase contract totals (at the option of the respondent) where one contract includes two or more FERC producer rate schedules or small producer certificates, provided that the same price is being paid for all gas purchased under the contract. If two or more prices are in effect under the same contract, separate details for each price shall be reported. The name and FERC rate schedule or small producer certificate docket number of each seller included in the contract total shall be listed on separate sheets, clearly cross-referenced. Where two or more prices are in effect, the sellers at each price are to be listed separately.

4. Purchases of less than 100,000 Mcf per year per contract from sellers not affiliated with the reporting company may (at the option of the respondent) be grouped by account number, except when the purchases were permanently discountinued during the reporting year. When grouped purchases are reported, the number of grouped purchases is to be reported in Column (a). Only Columns (a), (k), and (m) are to be completed for grouped purchases; however, the Commission may request additional details when necessary. Grouped non-jurisdictional purchases should be shown on a separate line.

5. Column instructions are as follows:

Columns (a) and (d) - In reporting the names of sellers under FERC rate schedules, use the names as they appear on the filed rate schedules. Abbreviations may be used where necessary. The code number to be used is the Commission-assigned number.

Column (b) - Give the name of the producing field only for purchases at the wellhead or from field lines. The plant name should be given for purchases from gasoline plant outlets. If purchases under a contract are from more than one field or plant, use the name of the one contributing the largest volume. Use a footnote to list the other fields or plants involved.

Column (c) - State the net rate in cents per Mcf as of December 31 for the reported year, applicable to the volume shown in Column (k). The net rate includes all applicable deductions and downward adjustments. The rate is effective and is filed pursuant to applicable statues and regulations and (as to FERC rates schedules) permitted by the Commission to become effective.

Columns (e) and (f) - General Services Administration location code designations are to be used to designate the state and county where the gas is received. Where gas is received in more than one county, use the code designation for the county having the largest volume, and by footnote list the other counties involved.

Column (g) - List the assigned Commission rate schedule number or small producer certificate docket number. Use the designation "NJ" in Column (g) to indicate non-jurisdictional purchases.

Column (h) - In some cases, two or more lines will be required to report a purchase, as when two or more rates are being paid under the same contract, or when purchases under the same rate schedule are charged to more than one account. If for such reasons the producer rate schedule or non-jurisdictional purchase contract appears on more than one line, enter a numerical code (selected by the respondent) in Column (h) to so indicate. Once established, the same numerical suffix is to be used for all subsequent years reporting of the purchase. If the purchase was permanently discontinued during the reporting year, so indicate by an asterisk(*) in column (h). Column (h) is also to be used to enter any Commission assigned letter rate schedule suffix (e.g. R.S. No. 22A).

Column (I) - Show date of the gas purchase contract. If gas is purchased under a renegotiated contract, show the dates of the original and renegotiated contracts on the following line in brackets. If new acreage is dedicated by ratification of an existing contract, show the date of the ratification rather than the date of the original contract. If gas is being sold from a different reservoir than the original dedicated acreage pursuant to Section 2.56 (f) (2) of the Commission's Rules of Practice and Procedure, place the letter "A" after the contract date.

Column (j) - Show, for each purchase, the approximate BTU per cubic foot, determined in accordance with the definition in item No. 7 of the General Instructions for FERC Form 2.

Column (k) - State the volume of purchased gas as finally measured for purposes of determining the amount payable for the gas. Include current year receipts of make-up gas that was paid for in prior years.

Column (l) - State the dollar amount (omit cents) paid and previously paid for the volumes of gas shown in Col. (k).

Column (m) - State the average cost per MCF to the neareast hundredth of a cent. (Column (l) divided by Column (k) multiplied by 100.)

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2012

STATE OR OREGON - GAS PURCHASES (Account 800, 801, 802, 803, 804, 804.1 and 805) (Con't)

LINE NO.	NAME OF SELLER (DESIGNATE ASSOCIATED COMPANIES) (a)	Name of Producing Field or Gasoline Plant (b)	Net Rate Effective December 31 (c)
1	804 Natural Gas City Gate Purchases		
2	Core firm supply		
3			
4	Peaking Services		
5			
6	Interstate Pipeline Transportation		
7			
8			
9	**TOTAL**		
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NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

STATE OR OREGON - GAS PURCHASES (Account 800, 801, 802, 803, 804, 804.1 and 805) (Con't)

7 Code (d)	State Code (e)	County Code (f)	Rate Schedule No. (g)	Rate Schedule Suffix (h)	Date of Contract (I)	Approx. BTU Per Cu Ft (j)	Gas Purchased - Mcf (14.73 psia 60 °F) (k)	Cost of Gas (l)	Cost Per Mcf (cents) (m)	LINE NO.
										1
						10.29	6,678,958	$ 31,589,663	472.97	2
										3
								$ 319,449	n/a	4
										5
								$ 6,196,658	n/a	6
										7
									n/a	8
							6,678,958	**$ 38,105,770**		9
										10
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NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2012

STATE OF OREGON - GAS USED IN UTILITY OPERATIONS - CREDIT (Accounts 810, 811 and 812)

1. Report below particulars of credits during the year to Accounts 810, 811 and 812, which offset charges to operating expenses or other accounts for the cost of gas from the respondent's own supply.
2. Natural gas means either natural gas unmixed, or any mixture of natural and manufactured gas.
3. If the reported MCF for any use is an estimated quantity, state such fact.
4. If any natural gas was used by the respondent for which charge was not made to the appropriate operating expenses or other account, list separately in column (c) the MCF of gas so used omitting entries in columns (d) and (e).
5. Pressure base of measurement, to be reported in columns (c) and (f) is 14.73 psia at 60 °F.

			Natural Gas			Manufactured Gas	
LINE NO.	PURPOSE FOR WHICH GAS WAS USED (a)	ACCOUNT CHARGED (b)	MCF OF GAS USED (14.73 PSIA AT 60 °F) (c)	AMOUNT OF CREDIT (d)	AMOUNT PER MCF (CENTS) (e)	MCF OF GAS USED (14.73 PSIA AT 60 °F) (f)	AMOUNT OF CREDIT (g)
1	810 Gas used for Compressor Station Fuel - Credit						
2	811 Gas used for Products Extraction - Credit						
3	(a) Gas shrinkage & other usage in respondent's own processing						
4	(b) Gas shrinkage, etc. for respondent's gas processed by others						
5	812 Gas used for Other Utility Operations - Credit	812	5,379	$ 25,871	0	0	0
6	(Report separately for each principal use. Group minor uses).						
7							
8							
9							
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24							
25	TOTAL		5,379	$ 25,871			

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NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

STATE OF OREGON - GAS ACCOUNT - NATURAL GAS

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent taking into consideration differences in pressure bases used in measuring MCF of natural gas received and delivered.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the MCF as reported in the schedules indicated for the respective items of receipts and deliveries.

LINE NO.	ITEM (a)	REFERENCE PAGE NO. (b)	MCF (14.73 PSIA AT 60 °F) (c)
1	**GAS RECEIVED**		Mcf
2	Natural gas produced		
3	LPG gas produced and mixed with natural gas		
4	Manufactured gas produced and mixed with natural gas		
5	Purchased gas:		
6	a. Wellhead		
7	b. Field lines		
8	c. Gasoline Plants		
9	d. Transmission line		
10	e. City gate under FERC rate schedules		6,631,525
11	f. LNG		
12	g. Other		
13	TOTAL GAS PURCHASED		6,631,525
14	Gas of others received for transportation		23,182,013
15	Receipts of respondents' gas transported or compressed by others		
16	Exchange gas received		
17	Gas withdrawn from underground storage		52,811
18	Gas received from LNG storage		
19	Gas received from LNG processing		
20	Other receipts: (specify)		
21	TOTAL RECEIPTS		29,866,349

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - GAS ACCOUNT - NATURAL GAS (Con't)

4. In a footnote report the volumes of gas from respondent's own production delivered to respondent's transmission system and included in natural gas sale.
5. If the respondent operates two or more systems which are not interconnected, separate schedules should be submitted. Insert pages should be used for this purpose.

LINE NO.	ITEM (a)	REFERENCE PAGE NO. (b)	MCF (14.73 PSIA AT 60 °F) (c)
	GAS RECEIVED		
22	Natural gas sales		
23	a. Field sales:		
24	(i) To interstate pipeline companies for resale pursuant		
25	to FERC rate schedules		
26	(ii) Retail industrial sales		
27	(iii) Other field sales		
28	TOTAL FIELD SALES		
29	b. Transmission systems sales:		
30	(i) To interstate pipeline co for resale under FERC rate schedules		
31	(ii) To intrastate pipeline companies and gas utilities for resale		
32	under FERC rate schedules		
33	(iii) Mainline Industrial sales under FERC certification		
34	(iv) Other mainline industrial sales		
35	(v) Other transmission system sales		
36	TOTAL TRANSMISSION SYSTEM SALES		
37	c. Local distribution by respondent:		
38	(i) Retail industrial sales		548,722
39	(ii) Other distribution system sales		6,191,391
40	TOTAL DISTRIBUTION SYSTEM SALES		6,740,113
41	d. Interdepartmental sales		
42	TOTAL SALES		6,740,113
43			
44	Deliveries of gas transported or compressed for:		
45	a. Other interstate pipeline companies		
46	b. Others		23,182,013
47	TOTAL, GAS TRANSPORTED OR COMPRESSED FOR OTHERS		23,182,013
48	Deliveries of respondent's gas for transportation or compression by others		
49	Exchange gas delivered		
50	Natural gas used by respondent		5,379
51	Natural gas delivered to underground storage		
52	Natural gas delivered to LNG storage		
53	Natural gas delivered to LNG processing		
54	Natural gas for franchise requirements		
55	Other deliveries (specify)		
56	TOTAL SALES & OTHER DELIVERIES UNACCOUNTED FOR		29,927,505
57	Production system losses		
58	Storage losses		
59	Transmission system losses		
60	Distribution system losses		(61,155)
61	Other losses (specify in so far as possible)		
62	TOTAL UNACCOUNTED FOR		(61,155)
63	TOTAL SALES, OTHER DELIVERIES & UNACCOUNTED FOR		29,866,350

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2012

STATE OF OREGON - Miscellaneous General Expeness (Account 930.2)

Report below the information called for concerning items included in miscellaneous general expenses.

LINE NO.	ITEMS (a)	TOTAL (b)	AMOUNT APPLICABLE TO STATE OF OREGON (c)	AMOUNT APPLICABLE TO OTHER STATES (d)
1	Industry association dues.	149,627	36,483	113,144
2	Experimental and general research expenses.			
	a. Gas Research Institute (GRI)			
	b. Other			
3	Publishing and distributing information and reports to stockholders, trustee, registrar, and transfer agent fees and expenses, and other expenses of servicing oustanding securities of the respondent			
4				
5	Bank and Other Finance Fees (paid to Bank of New York, Payflex and MDU for CNGC's share of corporate banking fees)	293,387	71,968	221,419
6	Director's Fees (paid to MDU for CNGC's share of director's expenses)	245,169	60,140	185,029
7	Miscellaneous under $250,000 (6 items)	(49,549)	(12,055)	(37,494)
8				
9				
10				
	TOTAL	**638,634**	**156,536**	**482,098**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - POLITICAL ADVERTISING

1. List all payments for advertising, the purpose of which is to aid or defeat any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation
2. Give the specific purpose of such advertising, when and where placed, and the account or accounts charged.
3. Report whole dollars only. Provide a total for each account and a grand total.

LINE NO.	DESCRIPTION (a)	ACCOUNT CHARGED (b)	AMOUNT (c)
1	NONE		
	TOTAL		

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

STATE OF OREGON - POLITICAL CONTRIBUTIONS

1. List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation.
2. The purpose of all contributions or payments should be clearly explained.
3. Report whole dollars only. Provide a total for each account and a grand total.

LINE NO.	DESCRIPTION (a)	ACCOUNT CHARGED (b)	AMOUNT (c)
1	NONE		
	TOTAL		

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - EXPENDITURES TO ANY PERSON OR ORGANIZATION HAVING AN AFFILIATED INTEREST FOR SERVICES, ETC.

1. Report all expenditures to any person or organization having an affiliated interest for service, advice, auditing, associating, sponsoring, engineering, managing, operating, financial, legal or other services. See Oregon Revised Statute 757.015 for definition of "affiliated interest."
2. Give reference if such expenditures have in the past been approved by the Commission. Describe the services received and the account or accounts charged. Report whole dollars only.

LINE NO.	DESCRIPTION (a)	ACCOUNT NUMBER (b)	TOTAL AMOUNT (c)	AMOUNT ASSIGNED TO OREGON (d)
1	MDU/MDUR Allocated - approved in Order 07-418	107	5,149,094	1,274,407
2	MDU/MDUR Allocated - approved in Order 07-418	426.1	8,955	2,197
3	MDU/MDUR Allocated - approved in Order 07-418	426.4	3,727	914
4	MDU/MDUR Allocated - approved in Order 07-418	813	185,730	45,560
5	MDU/MDUR Allocated - approved in Order 07-418	875	143,803	35,275
6	MDU/MDUR Allocated - approved in Order 07-418	880	255,221	62,606
7	MDU/MDUR Allocated - approved in Order 07-418	902	126,108	30,934
8	MDU/MDUR Allocated - approved in Order 07-418	903	4,214,963	1,033,930
9	MDU/MDUR Allocated - approved in Order 07-418	909	1,857	455
10	MDU/MDUR Allocated - approved in Order 07-418	920	4,265,246	1,046,265
11	MDU/MDUR Allocated - approved in Order 07-418	921	3,536,154	867,419
12	MDU/MDUR Allocated - approved in Order 07-418	922	(2,681)	(658)
13	MDU/MDUR Allocated - approved in Order 07-418	923	236,186	57,936
18	MDU/MDUR Allocated - approved in Order 07-418	925	737	181
19	MDU/MDUR Allocated - approved in Order 07-418	926	138,080	33,871
20	MDU/MDUR Allocated - approved in Order 07-418	930.1	34,099	8,365
21	MDU/MDUR Allocated - approved in Order 07-418	930.2	212,359	52,092
22	MDU/MDUR Allocated - approved in Order 07-418	931	1,287,717	315,877
23	Other Services	VAR	337,518	225,955
	TOTALS		20,134,873	5,093,581

NAME OF RESPONDENT **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT **Dec. 31, 2012**

STATE OF OREGON - Donations and Memberships

1. List all donations and membership expenditures made by the utility during the year and the accounts charged. Give the name, city and state of each organization to whom a donation has been made. Group donations under headings such as:
   a. Contributions to and memberships in charitable organizations
   b. Organizations of the utility industry
   c. Technical and professional organizations
   d. Commercial and trade organizations
   e. All other organizations and kinds of donations and contributions
2. List donations by type and group by the account charged. Report whole dollars only. Provide a total for each group of donations.

LINE NO.	DESCRIPTION (a)	ACCOUNT NUMBER (b)	TOTAL AMOUNT (c)	AMOUNT ASSIGNED TO OREGON (d)
1	*(a) Contributions to and memberships in charitable organizations:*			
2	CNGC Matching Contributions to Winter Help (WA and OR)	426.1	37,000	9,076
3	MDU Resource Foundation (Bismark, ND)	426.1	84,138	20,639
4	The FDN For Private Enterprise (Federal Way, WA)	426.1	2,500	613
5	Habitat for Humanity (Tri-Cities, WA)	426.1	3,250	797
6	United Way (Tri-Cities, WA and Bend OR)	426.1/921	2,643	1,553
10	American Red Cross (Tri-Cities, WA)	426.1	2,750	675
11	Boys & Girls Clubs (Tri-Cities, WA)	426.1	6,000	1,472
12	Columbia Industries (Tri-Cities, WA)	426.1	4,000	981
13	Other Organizations under $1,500 (54 organizations)	426.1/921	36,987	9,073
15	**Total contributions to and memberships in charitable organizations**		**179,268**	**44,879**
16	*(e) All Other Organizations and Kinds of Donations and Contributions:*			
17	Bismarck Mandan Area Chamber of Commerce (Bismarck,ND)	426.1	24,056	5,901
18	Association of Washington Businesses (Olympia, WA)	426.1/921	11,000	2,699
19	Tri-Cities Regional Chamber of Commerce (Tri-Cities, WA)	426.1/921	19,725	4,839
20	Other Organizations under $1,000 (17 organizations)	426.1/930.2	6,552	1,608
	Total all other organizations and kinds of donations and contributions		**61,333**	**15,046**
21	*(b) Organizations of the Utility Industry:*			
22	American Gas Association (Washington D.C.)	930.2	130,398	31,987
23	Northwest Gas Association (West Linn, OR)	921	48,292	11,846
24	Pipeline Association for Public Awareness (WA, OR)	921	23,270	5,708
25	Other Organizations under $1,000 (2 organizations)	921	1,500	745
26	**Total organizations of the utility industry**		**203,460**	**50,286**
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37	**TOTAL**		**444,061**	**110,211**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON - OFFICERS' SALARIES

1. Report below the name, title and salary for the year for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principle business unit, division or function (such as sales, administration or finance) and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent and date the change in incumbency was made.
3. Utilities which are required to file similar data with the Securities and Exchange Commission, may substitute a copy of item 4, Regulation S-K, identified as this schedule page. The substituted page(s) should be conformed to the size of this page.

LINE NO.	TITLE (a)	NAME OF OFFICER (b)	SALARY FOR YEAR TOTAL (a)	SALARY FOR YEAR OREGON (a)
1	President and CEO of MDU Utilities Group 1/	David L. Goodin	4/	
2	Chairman of the Board 2/	Terry D. Hildestad	4/	
3	Executive VP & General Manager 3/	K. Frank Morehouse	4/	
4	VP Operations	Eric P. Martuscelli	4/	
5	VP Reg Affrs, CAO, Asst. Treasurer and Asst. Secretary 3/	Scott W. Madison	4/	
6	EVP Bus. Dvlpmnt. And Gas Supply 1/	Dennis L. Haider	4/	
7	Assistant Secretary 2/	Julie A. Krenz	4/	
8	General Counsel and Secretary 2/	Paul K. Sandness	4/	
9	Assistant Secretary 2/	Daniel S. Kuntz	4/	
10				
11				
12				
13	1/ Salary includes amount allocated to CNGC from MDU			
14	2/ Salary includes amount allocated to CNGC from MDUR			
15	3/ Salary includes amount allocated to CNGC from IGC			
16	4/ Confidential salary data included on filed reports with OPUC.			
17				
18				
19				
20				
21				
22				
23				
24				
25				

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

STATE OF OREGON-DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during the year where the aggregate of such payments to a recipient was $25,000 or more including fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services, traffic settlements, amounts paid for general services and licenses, accruals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than *affiliates)* to any one corporation, institution, association, firm, partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed. Payments to a recipient by two or more companies within a single system under a cost sharing or other joint arrangement shall be considered a single item for reporting in this schedule and shall be shown in the report of the principal company in the joint arrangement (as measured by gross operating revenues) with references thereto in the reports of the other system companies in the joint agreement.
2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

LINE NO.	NAME OF RECIPIENT (a)	NATURE OF SERVICE (b)	AMOUNT OF PAYMENT (c)
1	Northwest Metal Fabrication and Pipe Inc	Construction	1,169,674
2	Pilchuck Contractors Inc	Construction	414,519
3	Gas Transmission NW Corp	Transportation	193,000
4	Day Wireless Systems	Consulting	143,901
5	Mears Group Inc.	Engineering	119,127
6	Veris Law Group PLLC	Environmental	65,209
7	Deloitte & Touche	Audit	59,703
8	Resource Data Inc	Consulting	47,981
9	Hickman Williams & Associates	Engineering	40,908
10	Vic Russell Construction Inc	Construction	29,045
11	Ramtech Software Solutions Inc	Consulting	25,496
12	High Desert Aggregate & Paving Inc	Construction	25,394
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27	**TOTAL**		**2,333,957**

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	**Dec. 31, 2012**

In order to help us with production of our Oregon Utility Statistics publication, please indicate:

Oregon Production Statistics(therms)		
Gas Produced		-
Gas Purchased		307,294,028
Total Receipts		307,294,028
Gas Sales		307,867,905
Gas used by Company		55,344
Gas Delivered to LNG Storage - Net		-
Losses & Billing Delay		(629,221)
Total Disbursements		307,294,028
Oregon Revenue by Service Class		
Residential	$	36,929,039
Commercial & Industrial	$	26,961,493
Firm	$	-
Interruptible	$	-
Transportation	$	4,012,257
Total	$	67,902,789
Gas Sold in Therms(Oregon)		
Residential		37,134,879
Commercial & Industrial		32,213,948
Firm		-
Interruptible		-
Transportation		238,519,078
Total		307,867,905
Average Number of Customers		
Residential		55,366
Commercial & Industrial		9,503
Firm		-
Interruptible		-
Transportation		34
Total		64,903

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MDU RESOURCES GROUP, INC.

ELECTRIC AND NATURAL GAS UTILITIES

PIPELINE AND ENERGY SERVICES

EXPLORATION AND PRODUCTION

CONSTRUCTION MATERIALS AND SERVICES

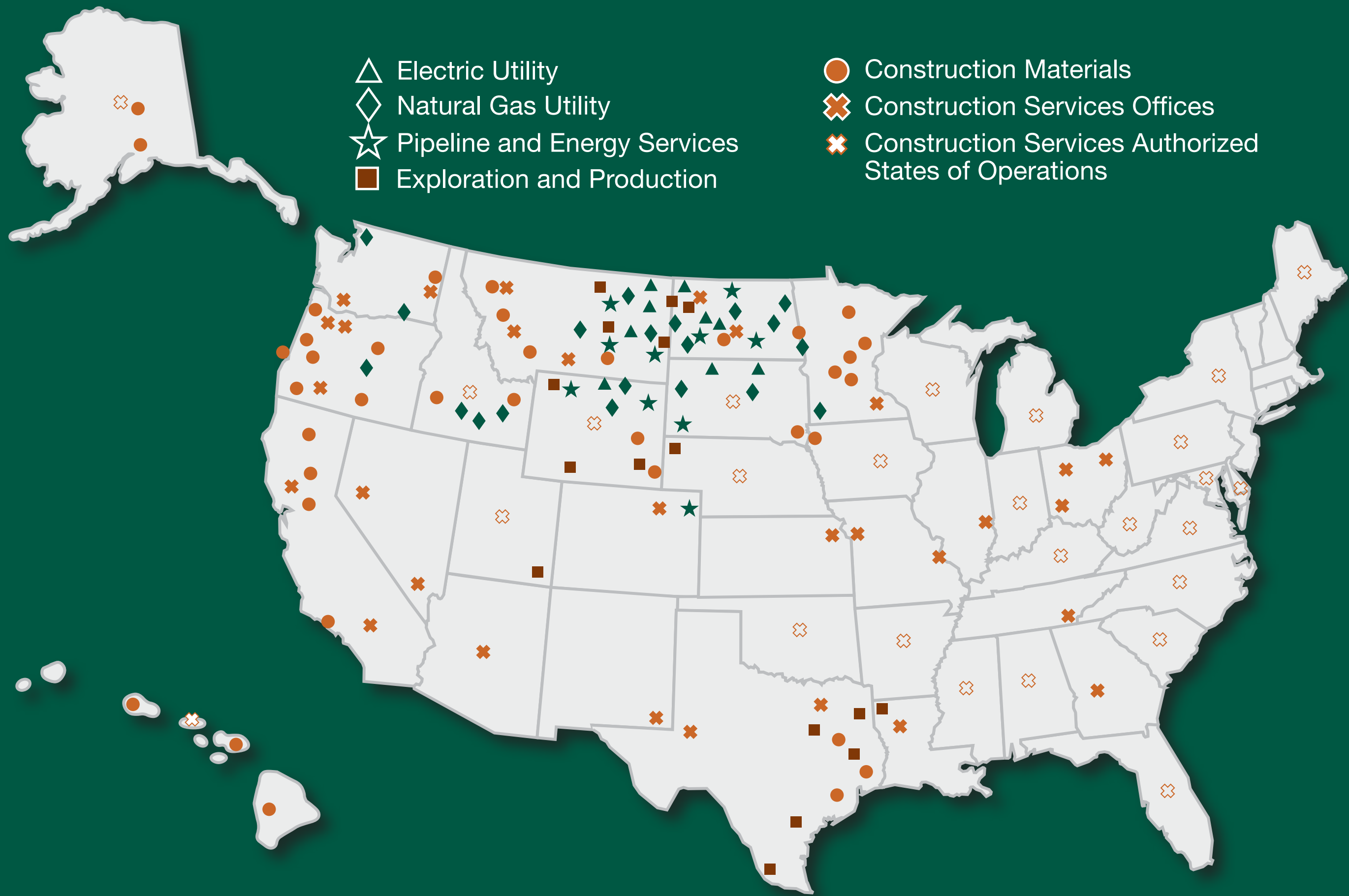
2012 Annual Report

Form 10-K

Proxy Statement

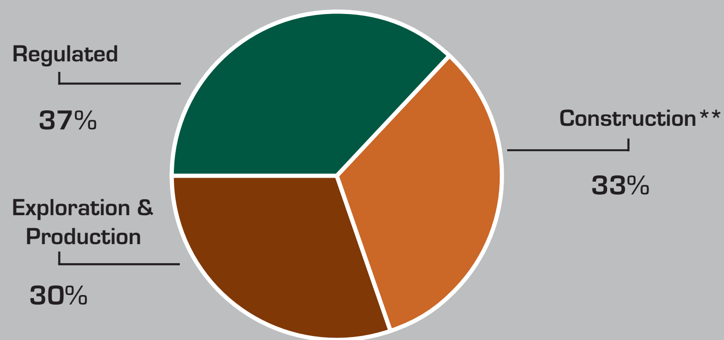
MDU RESOURCES GROUP, INC.

Building a Strong America®



We are a member of the S&P MidCap 400 index. We provide value-added natural resource products and related services that are essential to energy and transportation infrastructure, including regulated utilities and pipelines, exploration and production, and construction materials and services.

2012 Earnings*

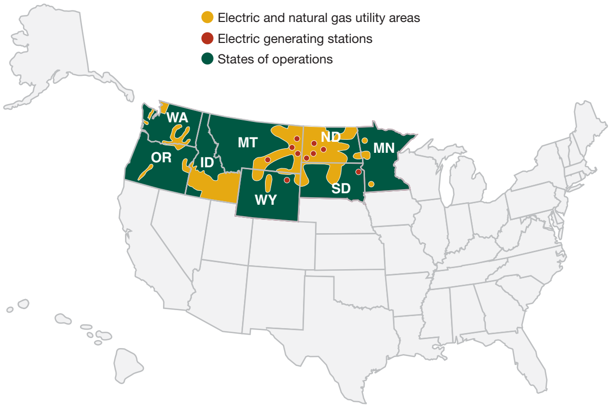


* Based on consolidated earnings before discontinued operations and excluding write-downs of oil and natural gas properties.

** Includes Other operations of 2 percent.

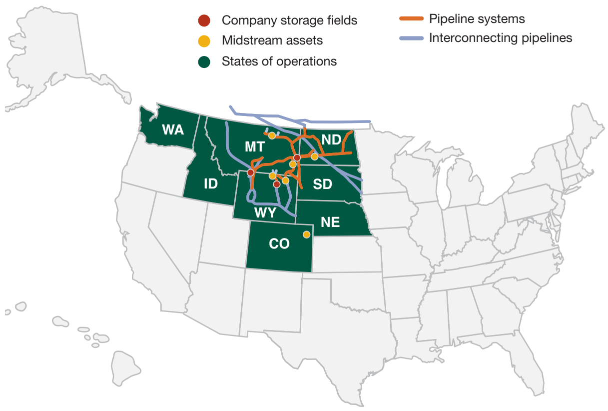
Territory	Company Description

REGULATED



Electric and Natural Gas Utilities

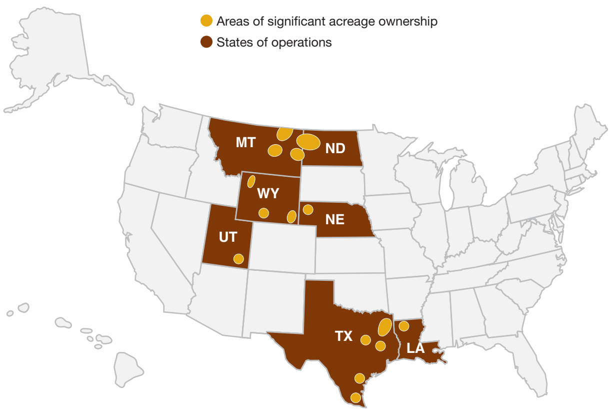
MDU Resources Group utility companies serve more than 991,000 customers. Montana-Dakota Utilities Co. generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Great Plains Natural Gas Co. distributes natural gas in western Minnesota and southeastern North Dakota. Cascade Natural Gas Corporation distributes natural gas in Oregon and Washington. Intermountain Gas Company distributes natural gas in southern Idaho. These operations also supply related value-added services.



Pipeline and Energy Services

The pipeline and energy services segment provides natural gas transportation, underground storage, processing and gathering services, as well as oil gathering, through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. It also provides cathodic protection and other energy-related management services.

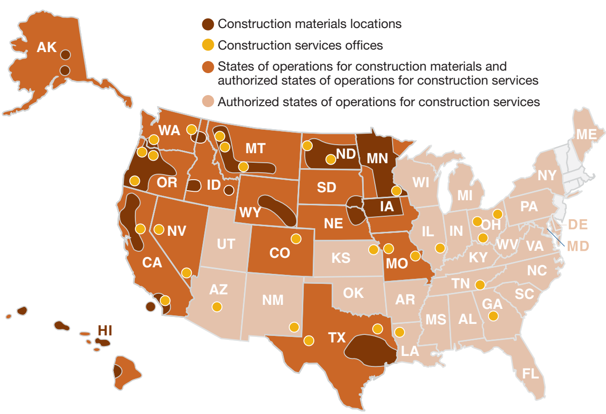
E&P



Exploration and Production

Fidelity Exploration & Production Company is engaged in oil and natural gas acquisition, exploration, development and production activities in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico.

CONSTRUCTION



Construction Materials and Services

MDU Resources Group has a number of construction businesses.

- Knife River Corporation mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mix concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated contracting services.
- The construction services segment specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes specialty equipment.

2012 Highlights	Key Statistics	A Look Ahead

- *Invested an all-time high of approximately $220 million in utility infrastructure, including $74 million to serve the growing customer base associated with Bakken oil development and completing pipeline projects to enhance the Pacific Northwest and Idaho systems.*
- *Received approval for advance determination of prudence from the North Dakota Public Service Commission to construct an 88-megawatt natural gas-fired electric generating facility near Mandan, North Dakota. The estimated $86 million project is expected to be in service in late 2014.*
- *Filed requests with the Montana Public Service Commission for a $3.5 million natural gas rate increase and the South Dakota Public Utilities Commission for a $1.5 million natural gas rate increase.*

Revenues (millions)	
Electric	$236.9
Natural gas	$754.8
Earnings (millions)	
Electric	$30.6
Natural gas	$29.4
Electric sales (million kWh)	
Retail	2,996.5
Sales for resale	14.1
Natural gas distribution (MMdk)	
Sales	93.8
Transportation	132.0
Corporate earnings contribution	
Electric	13%
Natural gas	13%

- *Beginning construction on the $86 million, 88-megawatt natural gas-fired electric generating facility near Mandan, North Dakota.*
- *Upgrading pollution control technology on several electric generating facilities, including a $125 million upgrade to Big Stone.*
- *Pursuing opportunities associated with potential development of high-voltage transmission lines and system enhancements targeted toward delivering energy to major markets.*
- *Constructing a 30-mile natural gas pipeline to the Hanford Nuclear Site in Washington.*
- *Continuing to meet the demands of the growing customer base in western North Dakota and eastern Montana.*

- *Announced a joint project with Calumet Specialty Products Partners LP to explore building and operating a 20,000-barrel-per-day diesel topping plant in southwestern North Dakota. Land has been purchased; engineering studies, permitting and construction planning are under way.*
- *Purchased a 50 percent interest in Whiting Oil and Gas Corp.'s Pronghorn natural gas and oil midstream assets near Belfield, North Dakota, in the Bakken region. Facilities include a natural gas processing plant, natural gas gathering pipeline system, natural gas residue line, crude oil gathering system, crude oil storage terminal and crude oil pipeline.*
- *Effective July 1, Williston Basin Interstate Pipeline Company, Bitter Creek Pipelines LLC and Total Corrosion Solutions changed their names to be part of the WBI Energy, Inc. group of companies.*

Revenues (millions)	$193.1
Earnings (millions)*	$26.6
Pipeline (MMdk)	
Transportation	137.7
Gathering	47.1
Corporate earnings contribution	11%

* *Includes a $15.0 million after-tax net benefit related to natural gas gathering operations litigation.*

- *Beginning construction of the 20,000-barrel-per-day diesel topping plant in southwestern North Dakota, a joint project with Calumet Specialty Products Partners LP, with an in-service date in late 2014.*
- *Constructing in 2014 a second pipeline to connect the planned Garden Creek II gas processing plant in northwestern North Dakota to deliver gas into the Northern Border Pipeline.*
- *Further investing approximately $20 million in the Pronghorn midstream facilities to enhance processing capabilities and extend the gathering pipeline systems.*
- *Continuing to pursue expanding facilities and services offered to customers within the company's geographic region, which is expanding most notably in the Bakken play in North Dakota and eastern Montana.*

- *Increased oil production by 36 percent. Oil production now makes up 37 percent of total production, compared to 14 percent in 2007.*
- *Acquired additional acres of leaseholds in Richland County, Montana, for a total of 60,000 net leasehold acres. The company now has approximately 127,000 net leasehold acres in the Bakken area.*
- *Continued exploratory drilling in the Paradox Basin Cane Creek Federal Unit in Utah, where the company holds approximately 83,000 net acres with an option to lease another 20,000 acres.*

Revenues (millions)	$448.6
Earnings (millions)**	$69.6
Production	
Oil (MBbls)	3,694
Natural gas liquids (MBbls)	828
Natural gas (MMcf)	33,214
Proved reserves	
Oil (MBbls)	33,453
Natural gas liquids (MBbls)	7,153
Natural gas (MMcf)	239,278
Corporate earnings contribution	30%

** *Excludes the effects of $246.8 million after-tax noncash charges relating to the write-downs of oil and natural gas properties.*

- *Continuing to proceed systematically in the Paradox Basin, anticipating $70 million in capital expenditures in 2013 with the potential to increase the investment based on results. Estimated gross ultimate recovery rates per well range from 250,000 to 1 million barrels.*
- *Pursuing acquisitions of additional leaseholds, with a focus on expanding existing positions as well as seeking new opportunities.*

- *Experienced an increase in the amount of construction materials private work versus public projects, with private work representing 14 percent of the backlog at year-end compared to 8 percent at year-end 2011.*
- *Congress passed a federal transportation bill that funds construction for highways, bridges and other transportation projects for two years.*
- *Expanded construction materials operations in North Dakota and utilized a new liquid asphalt terminal in Wyoming.*
- *Named the No. 13 solar contractor in the country, according to Solar Power World's Top 100 list.*
- *Had record sales and rentals for specialty power line equipment and materials for the second consecutive year.*
- *Expanded electrical materials distribution into North Dakota and specialty equipment sales and rentals into Georgia.*

Revenues (millions)	
Construction materials	$1,617.4
Construction services	$938.6
Earnings (millions)	
Construction materials	$32.4
Construction services	$38.4
Construction materials sales (millions)	
Aggregates (tons)	23.3
Asphalt (tons)	6.0
Ready-mix concrete (cubic yards)	3.2
Construction materials aggregate reserves (billion tons)	1.1
Corporate earnings contribution	
Construction materials	14%
Construction services	17%

- *Continuing to pursue opportunities to expand work in energy projects such as refineries, transmission, substations, utility services, solar, wind towers and geothermal.*
- *Continuing to pursue higher-margin private construction work where available, with a focus on increasing margins and cash flow while maximizing the value of the company's 1.1 billion tons of strategic aggregate reserves.*

Notes:
- *Corporate earnings contribution percentages exclude the effects of $246.8 million after-tax noncash charges relating to the write-downs of oil and natural gas properties and discontinued operations.*
- *The Other category contributed 2 percent of corporate earnings; it includes revenues of $10.4 million, income before discontinued operations of $4.8 million, and earnings of $18.4 million, including discontinued operations.*
- *Consolidated revenues reflect intersegment eliminations of $124.4 million.*

HIGHLIGHTS

Years Ended December 31,	2012	2011	Increase/Decrease Amount	Increase/Decrease Percent
	(In millions, where applicable)			
Operating revenues	**$4,075.4**	$4,050.5	$ 24.9	1
Operating income	**$ 19.2**	$ 406.4	$ (387.2)	(95)
Earnings (loss) on common stock:				
Earnings (loss) before discontinued operations	**$ (15.0)**	$ 225.2	$ (240.2)	(107)
Discontinued operations, net of tax	**13.6**	(12.9)	26.5	205
Earnings (loss) on common stock	**$ (1.4)**	$ 212.3	$ (213.7)	(101)
Earnings (loss) per common share – basic:				
Earnings (loss) before discontinued operations	**$ (.08)**	$ 1.19	$ (1.27)	(107)
Discontinued operations, net of tax	**.07**	(.07)	.14	200
Earnings (loss) per common share – basic	**$ (.01)**	$ 1.12	$ (1.13)	(101)
Earnings (loss) per common share – diluted:				
Earnings (loss) before discontinued operations	**$ (.08)**	$ 1.19	$ (1.27)	(107)
Discontinued operations, net of tax	**.07**	(.07)	.14	200
Earnings (loss) per common share – diluted	**$ (.01)**	$ 1.12	$ (1.13)	(101)
Dividends per common share	**$ .6750**	$ .6550	$ .02	3
Weighted average common shares outstanding – diluted	**188.8**	188.9	(.1)	–
Total assets	**$6,682.5**	$6,556.1	$ 126.4	2
Total equity	**$2,648.2**	$2,775.6	$ (127.4)	(5)
Total debt	**$ 1,773.2**	$1,424.7	$ 348.5	24
Capitalization ratios:				
Total common equity	**60%**	66%		
Total debt	**40**	34		
	100%	100%		
Return on average common equity	**(.1)%**	7.8%		
Price/earnings ratio	*	19.2x		
Book value per common share	**$ 13.95**	$ 14.62		
Market value as a percent of book value	**152.3%**	146.8%		
Employees	**8,629**	8,021		

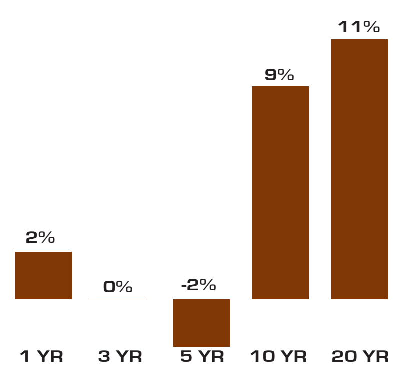
* Not meaningful due to effects of write-downs, as described below.

Note: The above information reflects after-tax noncash write-downs of oil and natural gas properties of $246.8 million in 2012.

Forward-looking statements: This Annual Report contains forward-looking statements within the meaning of section 21E of the Securities Exchange Act of 1934. Forward-looking statements should be read with the cautionary statements and important factors included in Part I, Forward-Looking Statements and Item 1A — Risk Factors of the company's 2012 Form 10-K. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words anticipates, estimates, expects, intends, plans, predicts and similar expressions.

Total Shareholder Returns

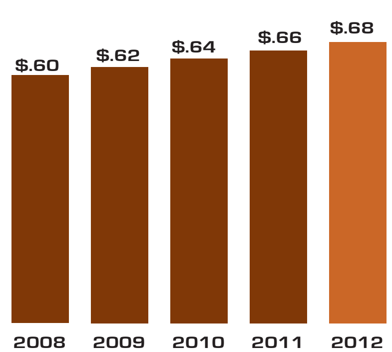
(as of December 31, 2012)



Dividends

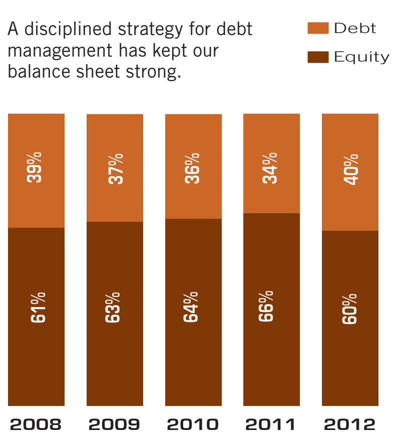
(per common share)

We have paid dividends uninterrupted for 75 years.



Capitalization Ratios

A disciplined strategy for debt management has kept our balance sheet strong.



REPORT TO STOCKHOLDERS

We have just completed year one of the largest investment program in our company's history, and the momentum it has created is a big first step toward re-establishing our track record of sustainable and substantial earnings growth.

We invested approximately $934 million in 2012 as the first installment of nearly $4 billion of capital expenditures that we expect to make through 2016; this year's investment will be more than $800 million. As the timeframe suggests, it will take several years to hit full stride, but we understand the importance of rebuilding growth as quickly as practicable.

However, we also are proud of our success in protecting your investment through the country's prolonged recession. We maintained a strong balance sheet, good credit rating and a healthy balance of equity and debt. The tradeoff was sacrificing the investments that drive growth in later years.

Our company had a net loss of $1.4 million, or a penny per share in 2012 primarily due to noncash, after-tax write-downs of about $247 million that are attributable to a ceiling test charge at our exploration and production group related to low natural gas prices.

Excluding discontinued operations and one-time charges in both years, adjusted earnings were $216.8 million or $1.15 per share last year, compared to $225.2 million or $1.19 per share in 2011. Adjusted earnings for 2012 were above the mid-range of earnings guidance that we provided during the year.

All of our businesses remain fundamentally strong, as our adjusted earnings demonstrate. However, we have higher expectations for our performance and believe that our blueprint for targeted investments, when fully implemented, is capable of driving long-term compound annual growth in the 7 to 10 percent range. The fourth quarter of 2012 provided a very early look at some of the paybacks we can expect from our capital program. For example, we began to see an earnings contribution from our expansion into the natural gas processing business, which we will discuss more fully later in this letter. In addition, our accelerated oil production strategy met important milestones.

In November, the Board of Directors increased the common stock dividend for the 22nd consecutive year. We remain committed to paying a competitive dividend, and are extremely proud of our record of uninterrupted quarterly dividend payments for 75 years.

Fidelity Achieves Production Growth Target

Our production business, Fidelity Exploration & Production, is making good progress on its plan to build a stronger balance of its oil and natural gas portfolios. With natural gas prices at low levels and expected to remain there well into the future, Fidelity is targeting its production efforts at oil.

Fidelity's largest oil producing property is in North Dakota's Bakken formation, where it owns approximately 127,000 net acres of leaseholds and has five drilling rigs operating. The Bakken has created a modern-day oil boom and has made North Dakota the nation's second-largest oil producer, behind Texas.

Oil production increased 36 percent over 2011, exceeding our growth target while achieving an oil reserve replacement rate of 267 percent. In the fourth quarter of last year oil accounted for 44 percent of Fidelity's production. Fidelity expects to increase oil production by an additional 25 to 30 percent this year.

This year, we expect to invest approximately $400 million to continue increasing oil and liquids production, with about half of that concentrated in the Bakken. We will continue to explore ways to maximize production in Utah's Paradox Basin, where Fidelity holds approximately 83,000 net exploratory leasehold acres. Based on our first four wells, we believe this location holds very significant potential. We also will continue building our liquids-rich production in Texas.

Midstream Business Expands

Our pipeline and energy services business, WBI Energy, is located in the heart of the Bakken, so it is ideally situated to benefit from the oil play and associated natural gas that is produced along with the oil. We operate the most extensive natural gas transportation system in the Bakken, with a FERC-regulated natural gas pipeline capable of moving 1 billion cubic feet per day and approximately 1,700 miles of operated field gathering lines.

Last year we continued to add capacity with pipelines transporting natural gas from processing plants to interstate pipelines. With completion of the latest addition, WBI Energy has quadrupled its Bakken takeaway capacity from 2010 levels. We have received sufficient customer commitments for an additional expansion of up to 200 million cubic feet per day. Pending regulatory approvals, that addition would go into service in 2014.

We also began an expansion of our midstream business with two investments that will diversify WBI Energy's capabilities and expand MDU Resources' vertically integrated investments in the Bakken oil play.

In May we purchased a 50 percent interest in a new natural gas processing plant and gathering system for both oil and natural gas. The plant can process 35,000 Mcf per day and is connected to our interstate pipeline system. The purchase also includes a crude oil storage terminal capable of storing 20,000 barrels. Production has been ramping up and we expect to receive a full year of benefits in 2013.

We recently announced that we have formed a partnership with Calumet Specialty Products Partners to build and operate a topping facility that will have the capability to refine 20,000 barrels a day of Bakken crude into diesel fuel. Depending on permitting approvals, construction could begin this spring and operations could begin in late 2014.

The plant will cost between $280 million to $300 million and will be located in western North Dakota, in the middle of a large and growing market. Diesel consumption in North Dakota is more than 53,000 barrels per day and is projected to increase to 75,000 barrels per day by 2025. The state's lone refinery produces about 22,000 barrels a day, so the rest of the diesel supply is imported.

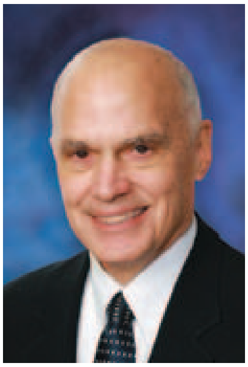
The refinery is a fine example of the value-added benefit that our corporate strategy provides when diversified businesses with complementary capabilities converge on a single project. We expect that Fidelity's Bakken production will provide some of the facility's crude oil. Our utility business will serve the facility's electricity needs. WBI Energy will supply natural gas service. And both of our construction businesses can supply materials and services needed to help build the facility.

Similar teamwork is common across our corporation. A number of our construction services businesses are working for our utility business in North Dakota's Bakken, helping build substations and distribution lines. One of our construction materials units is providing pad work for Fidelity's drilling rigs. A number of our construction services companies are teaming up to develop solar and other renewable energy projects.

These opportunities, and others like them, demonstrate that while our businesses' diversity of skills and capabilities are remarkable, at the end of the day the whole is stronger than the individual parts.

Utility Business Experiencing Customer Growth

Our utility business experienced good customer growth in 2012 and now serves 991,000 electric and natural gas customers, stretching across eight states from Minnesota to Oregon and Washington. Electricity sales increased by 4 percent.



Harry J. Pearce
Chairman of the Board

David L. Goodin
President and
Chief Executive Officer

The most significant growth took place in the Bakken, where the number of electric and natural gas customers grew by 9 percent and 7 percent, respectively. The Bakken area helped drive a 6 percent increase in North Dakota electricity sales, and we expect that trend to continue. A study last year by the North Dakota Transmission Authority projected that electricity demand in the Bakken will nearly double in the next five years and triple in the next 20 years.

To prepare for this growth and other needs across our system, capital investments of $242 million in 2012 and $252 million this year represent the largest capital spending in the history of our utility business. In the Bakken alone we invested about $74 million last year to serve the growing oil and natural gas customer base associated with oil development, and an additional $70 million is planned in 2013. This work will translate into earnings growth through the rate base.

Montana-Dakota Utilities expects to begin construction this year on an $86 million, 88-megawatt natural gas-fueled generating plant that will be located adjacent to our existing coal-fueled generating plant in Mandan, North Dakota. The plant, which is expected to begin operating in late 2014, will be a partial replacement for third-party contract capacity that expires in 2015. The North Dakota Public Service Commission has approved an advance determination of prudence for the project.

We also are installing a new emission control system at the Big Stone generating plant in South Dakota, which is co-owned by Montana-Dakota Utilities. The equipment is required by the South Dakota Regional Haze Program, which has been approved by the Environmental Protection Agency. Our utility's share of the project will be about $125 million, with completion scheduled for 2015.

All of our utilities are committed to delivering outstanding customer service, and we are pleased to note that Intermountain Gas Company in Idaho has been recognized as an industry leader. For the third straight year in 2012, Intermountain Gas earned first place among West Region midsize natural gas utilities in the J.D. Power and Associates Gas Utility Residential Customers Satisfaction Study. Congratulations to all of the employees at Intermountain Gas, and thank you for your outstanding performance.

Construction Businesses See Rebound in Markets

We are particularly pleased with the progress made by our construction businesses, which have borne much of the impact of the country's weak economy.

Our construction services and construction materials units posted their highest earnings since 2008 and 2009, respectively. They entered 2013 with a consolidated backlog of $731 million, $39 million higher than a year ago. Although competition remains intense, we are encouraged by an increasing number of bidding opportunities across our entire construction business.

Perhaps just as important at Knife River Corporation, our construction materials business, was an increase in the amount of privately funded work — mostly commercial and residential — which virtually disappeared during the recession. At year-end, private work represented 14 percent of Knife River's backlog.

The public works portion of the construction materials business continued to be centered on highway, airport and related transportation projects. That market received some stability last year when Congress passed a two-year transportation bill that continues federal funding for highway programs at approximately $40 billion a year. In addition, a number of states are increasing their infrastructure spending. North Dakota's governor, for example, has proposed a record two-year budget of $2.7 billion to fund transportation and other infrastructure improvements.

Our construction services business offers a wide diversity of specialty services, and several of those segments experienced a strong year in 2012. Our Oregon Electric Group, which provides electrical construction, systems and manufacturing services, reported record earnings. That also was the case at Wagner-Smith Equipment, which is a leading manufacturer of specialty equipment used to string electric power lines.

Capital Electric Line Builders, based in Kansas City, Missouri, sent 84 employees to help restore electricity in the wake of Hurricane Sandy. The crews spent more than two weeks in southern New York and New England, and were recognized by local utilities for their outstanding work. These employees regularly perform very demanding storm repair work around the country, and we are proud that they accomplish this with safety and professionalism.

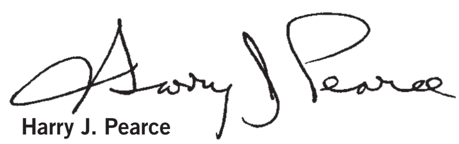
Bombard Renewable Energy, based in Las Vegas, recently was ranked among the leading solar contractors by an industry publication, Solar Power World. The company has installed more than 60 megawatts of solar energy projects, and participated in the construction of the world's first hybrid solar-geothermal power plant.

MDU Resources President and CEO Retires

We want to offer our congratulations and appreciation to Terry D. Hildestad, who retired as president and chief executive officer of MDU Resources on January 3. Terry's career at MDU Resources spanned 38 years, and he had been CEO since 2006. He provided outstanding leadership through both good and bad economic times. The value of the company's assets grew nearly 50 percent during the time Terry was president and CEO; he kept our company financially strong during the recession of the last several years; and he laid the groundwork for the growth initiatives that are now under way.

We also want to thank our employees — we number more than 10,000 during the peak construction season — for continuing to provide outstanding products and services to our customers, while exemplifying our corporate commitment to safety, integrity and service.

Finally, thank you for your investment in MDU Resources. We acknowledge and share your expectations for restoring the strong growth that has characterized MDU Resources' history. We have an aggressive plan that built a solid foundation in 2012, and we look forward to continuing that progress in 2013.

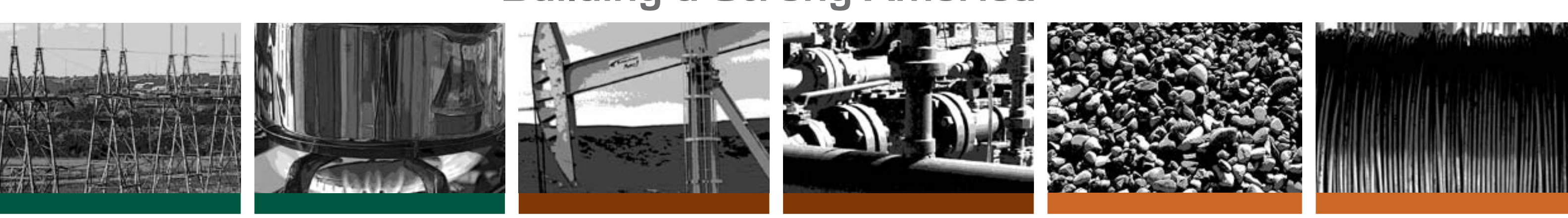


Harry J. Pearce
Chairman of the Board

David L. Goodin
President and Chief Executive Officer

February 22, 2013

Building a Strong America®



Board of Directors

Harry J. Pearce
70 (16)
Detroit, Michigan

Chairman of MDU Resources Board of Directors

Retired, formerly chairman of Hughes Electronics Corp., a subsidiary of General Motors Corp., and former vice chairman and director of GM; a director of several organizations

Expertise: Leadership, multinational business management, finance, engineering and law

David L. Goodin
51 (1)
Bismarck, North Dakota

President and chief executive officer of MDU Resources

Formerly president and chief executive officer of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation and Intermountain Gas Company

Thomas Everist
63 (18)
Sioux Falls, South Dakota

President and chairman of The Everist Co., a construction materials company; a director of several corporations

Expertise: Business management, construction and sand, gravel and aggregate production

Karen B. Fagg
59 (8)
Billings, Montana

Retired, formerly vice president of DOWL HKM and formerly chairman and majority owner of HKM Engineering Inc.; on the board of several organizations

Expertise: Engineering and business management

A. Bart Holaday
70 (5)
Placitas, New Mexico, and Grand Forks, North Dakota

Retired, formerly managing director of Private Markets Group of UBS Asset Management; on the board of several organizations

Expertise: Oil and natural gas industry, business development, finance and law

Dennis W. Johnson
63 (12)
Dickinson, North Dakota

Chairman, chief executive officer and president of TMI Corp., an architectural woodwork manufacturer; a former director of Federal Reserve Bank of Minneapolis

Expertise: Business management, engineering and finance

Thomas C. Knudson
66 (5)
Houston, Texas

President of Tom Knudson Interests, providing consulting services in energy, sustainable development and leadership; formerly senior vice president of human resources, government affairs and communications of ConocoPhillips

Expertise: Oil and natural gas industry, sustainable development and engineering

Richard H. Lewis
63 (8)
Denver, Colorado

Founder and former chairman and chief executive officer of Prima Energy Corp., an oil and natural gas exploration and production company, and chairman of Entre Pure Industries Inc., a privately held purified water and ice business; a member of the advisory board to Colorado State Bank and Trust

Expertise: Oil and natural gas industry, finance and business management

Patricia L. Moss
59 (10)
Bend, Oregon

Vice chairman of Cascade Bancorp and Bank of the Cascades, formerly president and chief executive officer of Cascade Bancorp and Bank of the Cascades; on the board of several organizations

Expertise: Finance, banking and human resources

J. Kent Wells
56 (1)
Denver, Colorado

Vice chairman of the corporation and president and chief executive officer of Fidelity Exploration & Production Company

Formerly an executive with one of the world's largest oil and natural gas production companies

John K. Wilson
58 (10)
Omaha, Nebraska

Formerly president of Durham Resources LLC, a privately held financial management company, and formerly a director of a mutual fund; on the board of several organizations

Expertise: Finance, accounting and natural gas industry

Audit Committee
Dennis W. Johnson, Chairman
A. Bart Holaday
Richard H. Lewis
John K. Wilson

Compensation Committee
Thomas Everist, Chairman
Karen B. Fagg
Thomas C. Knudson
Patricia L. Moss

Nominating and Governance Committee
Karen B. Fagg, Chairman
A. Bart Holaday
Richard H. Lewis
Patricia L. Moss

Numbers indicate age and years of service ( ) on the MDU Resources Board of Directors as of December 31, 2012, with the exception of David L. Goodin and J. Kent Wells, who joined the Board of Directors on January 4, 2013.

Corporate Management

David L. Goodin
51 (30)

President and Chief Executive Officer of MDU Resources

Serves on the company's Board of Directors and as chairman of the board of all major subsidiary companies; formerly president and chief executive officer of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation and Intermountain Gas Company

Steven L. Bietz
54 (32)

President and Chief Executive Officer of WBI Holdings, Inc.

Formerly held executive and management positions with WBI Holdings

Mark A. Del Vecchio
53 (10)

Vice President of Human Resources of MDU Resources

Formerly director of compensation and executive programs of MDU Resources

John G. Harp
60 (38)

Chief Executive Officer of Knife River Corporation and MDU Construction Services Group, Inc.

Formerly president and chief executive officer of MDU Construction Services Group and formerly owned construction services companies that were acquired by MDU Resources

K. Frank Morehouse
54 (12)

President and Chief Executive Officer of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation and Intermountain Gas Company

Formerly executive vice president and general manager of Cascade Natural Gas and Intermountain Gas

Cynthia J. Norland
58 (29)

Vice President of Administration of MDU Resources

Formerly associate general counsel of MDU Resources

Paul K. Sandness
58 (33)

General Counsel and Secretary of MDU Resources

Serves as general counsel and secretary of all major subsidiary companies; formerly senior attorney of MDU Resources and held other positions of increasing responsibility

William E. Schneider
64 (20)

Executive Vice President of Bakken Development of MDU Resources

Formerly president and chief executive officer of Knife River Corporation

Doran N. Schwartz
43 (8)

Vice President and Chief Financial Officer of MDU Resources

Serves as the senior financial officer and member of the board of directors of all major subsidiary companies; formerly chief accounting officer of MDU Resources

J. Kent Wells
56 (2)

Vice Chairman of the Corporation and President and Chief Executive Officer of Fidelity Exploration & Production Company

Formerly an executive with one of the world's largest oil and natural gas production companies

Numbers indicate age and years of service ( ) as of December 31, 2012.

Other Corporate and Senior Company Officers

William R. Connors, 51 (9)
Vice President of Renewable Resources of MDU Resources

Nicole A. Kivisto, 39 (18)
Vice President, Controller and Chief Accounting Officer of MDU Resources

Douglass A. Mahowald, 63 (31)
Treasurer and Assistant Secretary of MDU Resources

John P. Stumpf, 53 (21)
Vice President of Strategic Planning of MDU Resources

Management Changes

Terry D. Hildestad, president and chief executive officer of MDU Resources, retired January 3, 2013.

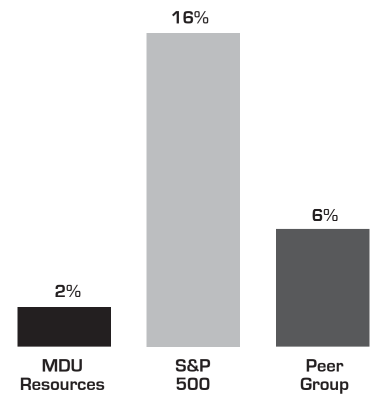
David L. Goodin was named president and chief executive officer of MDU Resources, and was appointed to the Board of Directors, effective January 4, 2013.

J. Kent Wells was appointed to the MDU Resources Board of Directors effective January 4, 2013, and was named vice chairman of the corporation.

K. Frank Morehouse was named president and chief executive officer of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation and Intermountain Gas Company effective January 4, 2013.

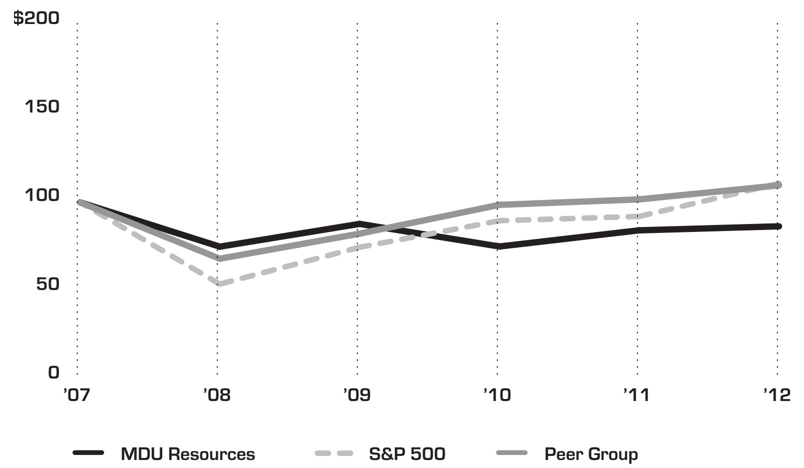
Comparison of One-Year Total Stockholder Return

(as of December 31, 2012)



Comparison of Five-Year Total Stockholder Return (in dollars)

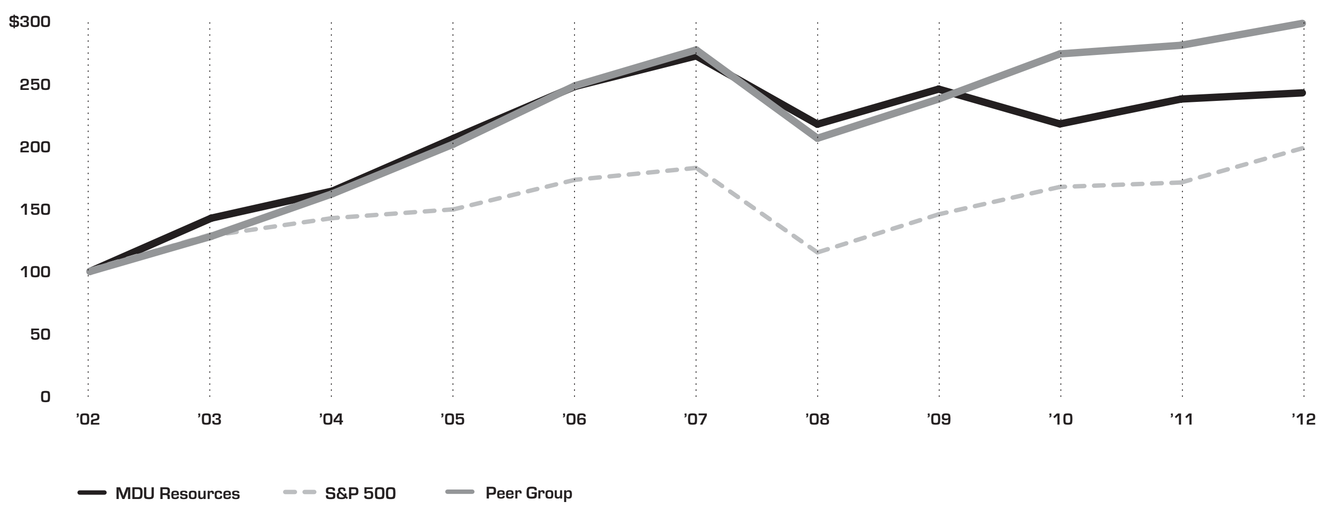
$100 invested December 31, 2007, in MDU Resources was worth $89.14 at year-end 2012.



	2007	2008	2009	2010	2011	2012
MDU Resources Group, Inc.	$100.00	$79.94	$90.24	$80.02	$87.33	$89.14
S&P 500 Index	100.00	63.00	79.67	91.68	93.61	108.59
Peer Group	100.00	74.49	85.83	98.85	101.33	107.66

Comparison of 10-Year Total Stockholder Return (in dollars)

$100 invested December 31, 2002, in MDU Resources was worth $242.92 at year-end 2012.



	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
MDU Resources Group, Inc.	$100.00	$142.64	$164.34	$206.56	$248.07	$272.50	$217.84	$245.92	$218.05	$237.99	$242.92
S&P 500 Index	100.00	128.68	142.69	149.70	173.34	182.87	115.21	145.70	167.64	171.18	198.58
Peer Group	100.00	128.12	162.21	202.00	248.61	277.30	206.57	238.00	274.11	281.00	298.53

Stockholder Return Comparison

Data is indexed to December 31, 2011, for the one-year total stockholder return comparison, December 31, 2007, for the five-year total stockholder return comparison and December 31, 2002, for the 10-year total stockholder return comparison for MDU Resources, the S&P 500 and the peer group. Total stockholder return is calculated using the December 31 price for each year. It is assumed that all dividends are reinvested in stock at the frequency paid, and the returns of each component peer issuer of the group are weighted according to the issuer's stock market capitalization at the beginning of the period.

Peer group issuers are Alliant Energy Corp., Atmos Energy Corp., Berry Petroleum Co., Black Hills Corp., Comstock Resources Inc., EMCOR Group Inc., EQT Corp., Granite Construction Inc., Martin Marietta Materials Inc., National Fuel Gas Co., Northwest Natural Gas Co., Pike Electric Corp., Quanta Services Inc., Questar Corp., SCANA Corp., SM Energy Co., Southwest Gas Corp., Sterling Construction Co. Inc., Swift Energy Co., Texas Industries Inc., Vectren Corp., Vulcan Materials Co. and Whiting Petroleum Corp.

During 2012, Southern Union Co. was merged with another company. As a result, the company was removed from the peer group for the entire period shown in the performance graphs.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2012

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 1-3480

MDU RESOURCES GROUP, INC.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	41-0423660 (I.R.S. Employer Identification No.)

1200 West Century Avenue
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(Address of principal executive offices)
(Zip Code)

(701) 530-1000
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $1.00	New York Stock Exchange

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

Preferred Stock, par value $100
(Title of Class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ 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. Yes ☐ No ☒.

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

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

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

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

Large accelerated filer ☒ Accelerated filer ☐ Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

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

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2012: $4,080,627,732.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 15, 2013: 188,830,529 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of the registrant's 2013 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

Part I

Part II

Part III

Part IV

The following abbreviations and acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
Alusa	Tecnica de Engenharia Electrica – Alusa
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
BART	Best available retrofit technology
Bbl	Barrel
Bcf	Billion cubic feet
Bicent	Bicent Power LLC
Big Stone Station	450-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Black Hills Power	Black Hills Power and Light Company
BLM	Bureau of Land Management
BOE	One barrel of oil equivalent – determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas
BOEPD	Barrels of oil equivalents per day
BOPD	Barrels of oil per day
Brazilian Transmission Lines	Company's equity method investment in ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE were sold in the fourth quarter of 2010 and a portion of the ownership interest in ECTE was sold in the third quarter of 2012 and the fourth quarters of 2011 and 2010)
Btu	British thermal unit
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CELESC	Centrais Elétricas de Santa Catarina S.A.
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
CEMIG	Companhia Energética de Minas Gerais
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Clean Air Act	Federal Clean Air Act
Clean Water Act	Federal Clean Water Act
Colorado State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EBITDA	Earnings before interest, taxes, depreciation and amortization
ECTE	Empresa Catarinense de Transmissão de Energia S.A. (5.01 percent ownership interest at December 31, 2012, 2.5, 2.5 and 14.99 percent ownership interests were sold in the third quarter of 2012 and the fourth quarters of 2011 and 2010, respectively)
EIN	Employer Identification Number
ENTE	Empresa Norte de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
EPA	U.S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ERTE	Empresa Regional de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
ESA	Endangered Species Act
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
Hawaiian Cement	Hawaiian Cement, an indirect wholly owned subsidiary of Knife River
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IP rate	Initial production rate
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
JTL	JTL Group, Inc., an indirect wholly owned subsidiary of Knife River
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River – Northwest	Knife River Corporation – Northwest, an indirect wholly owned subsidiary of Knife River (previously Morse Bros., Inc., name changed effective January 1, 2010)
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour

FORM 10-K

LPP	Lea Power Partners, LLC, a former indirect wholly owned subsidiary of Centennial Resources (member interests were sold in October 2006)
LWG	Lower Willamette Group
MBbls	Thousands of barrels
MBOE	Thousands of BOE
Mcf	Thousand cubic feet
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand decatherms
MDU Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial Resources
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MMBOE	Millions of BOE
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million decatherms
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana Department of Environmental Quality
Montana First Judicial District Court	Montana First Judicial District Court, Lewis and Clark County
Montana Seventeenth Judicial District Court	Montana Seventeenth Judicial District Court, Phillips County
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NEPA	National Environmental Policy Act
New York Supreme Court	Supreme Court of the State of New York, County of New York
NGL	Natural gas liquids
NSPS	New Source Performance Standards
Oil	Includes crude oil and condensate
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
PDP	Proved developed producing
PRC	Planning resource credit – a MW of demand equivalent assigned to generators by the Midwest ISO for meeting system reliability requirements
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
Proxy Statement	Company's 2013 Proxy Statement
PRP	Potentially Responsible Party
psi	pounds per square inch
PUD	Proved undeveloped
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
RP	Rehabilitation plan
Ryder Scott	Ryder Scott Company, L.P.
SDPUC	South Dakota Public Utilities Commission
SEC	U.S. Securities and Exchange Commission
SEC Defined Prices	The average price of oil and natural gas during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions
Securities Act	Securities Act of 1933, as amended
Securities Act Industry Guide 7	Description of Property by Issuers Engaged or to be Engaged in Significant Mining Operations
Sheridan System	A separate electric system owned by Montana-Dakota
SMCRA	Surface Mining Control and Reclamation Act
SourceGas	SourceGas Distribution LLC
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada
WBI Energy Midstream	WBI Energy Midstream, LLC, an indirect wholly owned subsidiary of WBI Holdings (previously Bitter Creek Pipelines, LLC, name changed effective July 1, 2012)
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings (previously Williston Basin Interstate Pipeline Company, name changed effective July 1, 2012)
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
Westmoreland	Westmoreland Coal Company
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

Forward-Looking Statements

This Form 10-K contains forward-looking statements within the meaning of Section 21E of the Exchange Act. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words “anticipates,” “estimates,” “expects,” “intends,” “plans,” “predicts” and similar expressions, and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 – MD&A – Prospective Information.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company’s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management’s examination of historical operating trends, data contained in the Company’s records and other data available from third parties. Nonetheless, the Company’s expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A – Risk Factors.

Items 1 and 2. Business and Properties

General

The Company is a diversified natural resource company, which was incorporated under the laws of the state of Delaware in 1924. Its principal executive offices are at 1200 West Century Avenue, P.O. Box 5650, Bismarck, North Dakota 58506-5650, telephone (701) 530-1000.

Montana-Dakota, through the electric and natural gas distribution segments, generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Cascade distributes natural gas in Oregon and Washington. Intermountain distributes natural gas in Idaho. Great Plains distributes natural gas in western Minnesota and southeastern North Dakota. These operations also supply related value-added services.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings (comprised of the pipeline and energy services and the exploration and production segments), Knife River (construction materials and contracting segment), MDU Construction Services (construction services segment), Centennial Resources and Centennial Capital (both reflected in the Other category).

The Company’s equity method investment in ECTE is reflected in the Other category. For additional information, see Item 8 – Note 4.

As of December 31, 2012, the Company had 8,629 employees with 156 employed at MDU Resources Group, Inc., 994 at Montana-Dakota, 35 at Great Plains, 275 at Cascade, 222 at Intermountain, 603 at WBI Holdings, 2,964 at Knife River and 3,380 at MDU Construction Services. The number of employees at certain Company operations fluctuates during the year depending upon the number and size of construction projects. The Company considers its relations with employees to be satisfactory.

The following information regarding the number of employees represented by labor contracts is as of December 31, 2012.

At Montana-Dakota and WBI Energy Transmission, 353 and 81 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2015, and March 31, 2014, for Montana-Dakota and WBI Energy Transmission, respectively.

At Cascade, 104 employees are represented by the ICWU. The labor contract with the field operations group is effective through April 1, 2015.

At Intermountain, 116 employees are represented by the UA. Labor contracts with such employees are in effect through September 30, 2013.

Knife River operates under 43 labor contracts that represent approximately 590 of its construction materials employees. Knife River is in negotiations on 4 of its labor contracts.

MDU Construction Services has 168 labor contracts representing the majority of its employees. The majority of the labor contracts contain provisions that prohibit work stoppages or strikes and provide for binding arbitration dispute resolution in the event of an extended disagreement.

The Company's principal properties, which are of varying ages and are of different construction types, are generally in good condition, are well maintained and are generally suitable and adequate for the purposes for which they are used.

The financial results and data applicable to each of the Company's business segments, as well as their financing requirements, are set forth in Item 7 – MD&A and Item 8 – Note 15 and Supplementary Financial Information.

The operations of the Company and certain of its subsidiaries are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations and state hazard communication standards. The Company believes that it is in substantial compliance with these regulations, except as to what may be ultimately determined with regard to items discussed in Environmental matters in Item 8 – Note 19. There are no pending CERCLA actions for any of the Company's properties, other than the Portland, Oregon, Harbor Superfund Site and one of the manufactured gas plant sites in Washington.

The Company produces GHG emissions primarily from its fossil fuel electric generating facilities, as well as from natural gas pipeline and storage systems, operations of equipment and fleet vehicles, and oil and natural gas exploration and development activities. GHG emissions also result from customer use of natural gas for heating and other uses. As interest in reductions in GHG emissions has grown, the Company has developed renewable generation with lower or no GHG emissions. Governmental legislative and regulatory initiatives regarding environmental and energy policy are continuously evolving and could negatively impact the Company's operations and financial results. Until legislation and regulation are finalized, the impact of these measures cannot be accurately predicted. The Company will continue to monitor legislative and regulatory activity related to environmental and energy policy initiatives. Disclosure regarding specific environmental matters applicable to each of the Company's businesses is set forth under each business description later. In addition, for a discussion of the Company's risks related to environmental laws and regulations, see Item 1A – Risk Factors.

This annual report on Form 10-K, the Company's quarterly reports on Form 10-Q, the Company's current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act are available free of charge through the Company's Web site as soon as reasonably practicable after the Company has electronically filed such reports with, or furnished such reports to, the SEC. The Company's Web site address is www.mdu.com. The information available on the Company's Web site is not part of this annual report on Form 10-K.

Electric

General Montana-Dakota provides electric service at retail, serving more than 131,000 residential, commercial, industrial and municipal customers in 177 communities and adjacent rural areas as of December 31, 2012. The principal properties owned by Montana-Dakota for use in its electric operations include interests in 10 electric generating facilities and three small portable diesel generators, as further described under System Supply, System Demand and Competition, approximately 3,100 and 4,700 miles of transmission and distribution lines, respectively and 51 transmission and 268 distribution substations. Montana-Dakota has obtained and holds, or is in the process of renewing, valid and existing franchises authorizing it to conduct its electric operations in all of the municipalities it serves where such franchises are required. Montana-Dakota intends to protect its service area and seek renewal of all expiring franchises. At December 31, 2012, Montana-Dakota's net electric plant investment was $676.0 million.

The percentage of Montana-Dakota's 2012 retail electric utility operating revenues by jurisdiction is as follows: North Dakota – 62 percent; Montana – 22 percent; Wyoming – 11 percent; and South Dakota – 5 percent. Retail electric rates, service, accounting and certain security issuances are subject to regulation by the NDPSC, MTPSC, SDPUC and WYPSC. The interstate transmission and wholesale electric power operations of Montana-Dakota also are subject to regulation by the FERC under provisions of the Federal Power Act, as are interconnections with other utilities and power generators, the issuance of securities, accounting and other matters.

Through the Midwest ISO, Montana-Dakota has access to wholesale energy, ancillary services and capacity markets. The Midwest ISO is a regional transmission organization responsible for operational control of the transmission systems of its members. The Midwest ISO provides security center operations, tariff administration and operates day-ahead and real-time energy markets, ancillary services and capacity markets. As a member of Midwest ISO, Montana-Dakota's generation is sold into the Midwest ISO energy market and its energy needs are purchased from that market.

System Supply, System Demand and Competition Through an interconnected electric system, Montana-Dakota serves markets in portions of western North Dakota, including Bismarck, Mandan, Dickinson and Williston; eastern Montana, including Glendive and Miles City; and northern South Dakota, including Mobridge. The maximum electric peak demand experienced to date attributable to Montana-Dakota's sales to retail customers on the interconnected system was 573,587 kW in July 2012. Montana-Dakota's latest forecast for its interconnected system indicates that its annual peak will continue to occur during the summer and the sales growth rate through 2017 will approximate 5 percent annually. The interconnected system consists of nine electric generating facilities and three small portable diesel generators, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 488,905 kW and total net PRCs of 443.6 in 2012. PRCs are a MW of demand equivalent measure and are allocated to individual generators to meet supply obligations within the Midwest ISO. For 2012, Montana-Dakota's total PRCs, including its firm purchase power contracts, were 552.8. Montana-Dakota's peak demand supply obligation, including firm purchase power contracts, within the Midwest ISO was 550.7 PRCs for 2012. Montana-Dakota's four principal generating stations are steam-turbine generating units using coal for fuel. The nameplate rating for Montana-Dakota's ownership interest in these four stations (including interests in the Big Stone Station and the Coyote Station, aggregating 22.7 percent and 25.0 percent, respectively) is 327,758 kW. Two combustion turbine peaking stations, two wind electric generating facilities, a heat recovery electric generating facility and three small portable diesel generators supply the balance of Montana-Dakota's interconnected system electric generating capability.

Montana-Dakota has a contract for capacity of 110 MW for the period June 1, 2012 to May 31, 2013, 115 MW for the period June 1, 2013 to May 31, 2014 and 120 MW for the period June 1, 2014 to May 31, 2015. Energy also will be purchased as needed, or if more economical, from the Midwest ISO market. In 2012, Montana-Dakota purchased approximately 27 percent of its net kWh needs for its interconnected system through the Midwest ISO market.

Montana-Dakota plans to construct and operate an 88-MW simple-cycle natural gas turbine and associated facilities, with an estimated project cost of $86 million and a projected in-service date late 2014. The capacity is necessary to meet the requirements of Montana-Dakota's integrated electric system customers and will be a partial replacement for third-party contract capacity expiring in 2015. Advance determination of prudence and a Certificate of Public Convenience and Necessity have been received from the NDPSC for construction and operation of the natural gas turbine. A Certificate of Site Compatability was issued for the turbine by the NDPSC on December 21, 2012.

Through the Sheridan System, Montana-Dakota serves Sheridan, Wyoming, and neighboring communities. The maximum peak demand experienced to date attributable to Montana-Dakota sales to retail customers on that system was approximately 61,501 kW in July 2012. Montana-Dakota has a power supply contract with Black Hills Power to purchase up to 49,000 kW of capacity annually through December 31, 2016. Wygen III serves a portion of the needs of its Sheridan-area customers.

The following table sets forth details applicable to the Company's electric generating stations:

Generating Station	Type	Nameplate Rating (kW)	2012 PRCs (a)	2012 Net Generation (kWh in thousands)
Interconnected System:				
North Dakota:				
Coyote (b)	Steam	103,647	98.2	557,130
Heskett	Steam	86,000	85.2	476,957
Glen Ullin	Heat Recovery	7,500	4.2	38,996
Cedar Hills	Wind	19,500	3.9	62,727
Diesel Units	Oil	5,475	1.9	470
South Dakota:				
Big Stone (b)	Steam	94,111	103.4	590,867
Montana:				
Lewis & Clark	Steam	44,000	52.1	253,721
Glendive	Combustion Turbine	75,522	69.1	10,596
Miles City	Combustion Turbine	23,150	19.5	1,573
Diamond Willow	Wind	30,000	6.1	90,956
		488,905	443.6	2,083,993
Sheridan System:				
Wyoming:				
Wygen III (b)	Steam	28,000	N/A	215,693
		516,905	443.6	2,299,686

(a) Interconnected system only. The Midwest ISO requires generators to obtain their summer capability, or PRCs, by applying the generator's forced outage factor against the results of a generator output verification test. Wind generator's PRCs are calculated based on a wind capacity study performed annually by the Midwest ISO. PRCs are used to meet supply obligations with the Midwest ISO.

(b) Reflects Montana-Dakota's ownership interest.

Virtually all of the current fuel requirements of the Coyote, Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland under contracts that expire in May 2016, April 2016 and December 2017, respectively. The Coyote coal supply agreement provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station or 30,000 tons per week, whichever may be the greater quantity at contracted pricing. The Heskett and Lewis & Clark coal supply agreements provide for the purchase of coal necessary to supply the coal requirements of these stations at contracted pricing. Montana-Dakota estimates the Heskett and Lewis & Clark coal requirement to be in the range of 450,000 to 550,000 tons and 250,000 to 350,000 tons per contract year, respectively.

On October 10, 2012, Montana-Dakota entered into a contract with Coyote Creek for coal supply to the Coyote Station beginning May 2016 until December 2040. Montana-Dakota estimates the Coyote Station coal supply agreement to be approximately 2.5 million tons per contract year. For more information, see Item 8 – Note 19.

On January 14, 2013, Montana-Dakota entered into a coal supply agreement, which meets a portion of the Big Stone Station's fuel requirements, for the purchase of 500,000 tons in 2013, 1.0 million tons in 2014, 1.0 million tons in 2015, and 500,000 tons in 2016 with Peabody Coalsales, LLC at contracted pricing. The remainder of the Big Stone Station fuel requirements will be secured through separate future contracts.

Montana-Dakota has a coal supply agreement with Wyodak Resources Development Corp., which provides for the purchase of coal necessary to supply the coal requirements of Wygen III at contracted pricing through June 1, 2060. Montana-Dakota estimates the maximum annual coal consumption of the facility to be 585,000 tons.

The average cost of coal purchased, including freight, at Montana-Dakota's electric generating stations (including the Big Stone, Coyote and Wygen III stations) was as follows:

Years ended December 31,	**2012**	2011	2010
Average cost of coal per MMBtu	**$ 1.69**	$ 1.62	$ 1.55
Average cost of coal per ton	**$24.77**	$23.38	$22.60

Montana-Dakota expects that it has secured adequate capacity available through existing baseload generating stations, renewable generation, turbine peaking stations, demand reduction programs and firm contracts to meet the peak customer demand requirements of its customers through mid-2015. Future capacity that is needed to replace contracts and meet system growth requirements is expected to be met by constructing new generation resources, or acquiring additional capacity through power purchase contracts or the Midwest ISO capacity auction. For additional information regarding potential power generation projects, see Item 7 – MD&A – Prospective Information – Electric and natural gas distribution.

Montana-Dakota has major interconnections with its neighboring utilities and considers these interconnections adequate for coordinated planning, emergency assistance, exchange of capacity and energy and power supply reliability.

Montana-Dakota is subject to competition in varying degrees, in certain areas, from rural electric cooperatives, on-site generators, co-generators and municipally owned systems. In addition, competition in varying degrees exists between electricity and alternative forms of energy such as natural gas.

Regulatory Matters and Revenues Subject to Refund In North Dakota, Montana-Dakota reflects monthly increases or decreases in fuel and purchased power costs (including demand charges) and is deferring electric fuel and purchased power costs that are greater or less than amounts presently being recovered through its existing rate schedules. In Montana, a monthly Fuel and Purchased Power Tracking Adjustment mechanism allows Montana-Dakota to reflect 90 percent of the increases or decreases in fuel and purchased power costs (including demand charges) and Montana-Dakota is deferring 90 percent of costs that are greater or less than amounts presently being recovered through its existing rate schedules. A fuel adjustment clause contained in South Dakota jurisdictional electric rate schedules allows Montana-Dakota to reflect monthly increases or decreases in fuel and purchased power costs (excluding demand charges). In Wyoming, an annual Electric Power Supply Cost Adjustment mechanism allows Montana-Dakota to reflect increases or decreases in purchased power costs (including demand charges but excluding increases or decreases from base coal price) related to power supply and Montana-Dakota is deferring costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 14 to 25 months from the time such costs are paid. For additional information, see Item 8 – Note 6.

Environmental Matters Montana-Dakota's electric operations are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations; and state hazard communication standards. Montana-Dakota believes it is in substantial compliance with these regulations.

Montana-Dakota's electric generating facilities have Title V Operating Permits, under the Clean Air Act, issued by the states in which they operate. Each of these permits has a five-year life. Near the expiration of these permits, renewal applications are submitted. Permits continue in force beyond the expiration date, provided the application for renewal is submitted by the required date, usually six months prior to expiration. No Title V Operating Permits required renewal in 2012. The Title V Operating Permit renewal notice for the Coyote Station will be submitted to the North Dakota Department of Health in 2013. The Title V Operating Permit for the Williston turbine facility was terminated since the facility was no longer in operation and was demolished in 2012.

State water discharge permits issued under the requirements of the Clean Water Act are maintained for power production facilities on the Yellowstone and Missouri rivers. These permits also have five-year lives. Montana-Dakota renews these permits as necessary prior to expiration. Other permits held by these facilities may include an initial siting permit, which is typically a one-time, preconstruction permit issued by the state; state permits to dispose of combustion by-products; state authorizations to withdraw water for operations; and Army Corps permits to construct water intake structures. Montana-Dakota's Army Corps permits grant one-time permission to construct and do not require renewal. Other permit terms vary and the permits are renewed as necessary.

Montana-Dakota's electric operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the RCRA. Montana-Dakota routinely handles PCBs from its electric operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required.

Montana-Dakota incurred $9.0 million of environmental capital expenditures in 2012. Capital expenditures are estimated to be $35 million, $65 million and $37 million in 2013, 2014 and 2015, respectively, to maintain environmental compliance as new emission controls are required, including the installation of a BART air quality control system at the Big Stone Station. Projects for 2013 through 2015 will also include sulfur-dioxide, nitrogen oxide and mercury and non-mercury metals control equipment installation at electric generating stations. Montana-Dakota's capital and operational expenditures could also be affected in a variety of ways by future air and wastewater effluent discharge regulation, as well as potential new GHG legislation or regulation. In particular, such GHG legislation or regulation would likely increase capital expenditures for renewable energy resources and operational costs associated with GHG emissions compliance until carbon capture technology becomes economical, at which time capital expenditures may be necessary to incorporate such technology into existing or new generating facilities. Montana-Dakota expects that it will recover the operational and capital expenditures for GHG regulatory compliance in its rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

Natural Gas Distribution

General The Company's natural gas distribution operations consist of Montana-Dakota, Great Plains, Cascade and Intermountain, which sell natural gas at retail, serving over 859,000 residential, commercial and industrial customers in 334 communities and adjacent rural areas across eight states as of December 31, 2012, and provide natural gas transportation services to certain customers on their systems. These services are provided through distribution systems aggregating approximately 18,200 miles. The natural gas distribution operations have obtained and hold, or are in the process of renewing, valid and existing franchises authorizing them to conduct their natural gas operations in all of the municipalities they serve where such franchises are required. These operations intend to protect their service areas and seek renewal of all expiring franchises. At December 31, 2012, the natural gas distribution operations' net natural gas distribution plant investment was $1.1 billion.

The percentage of the natural gas distribution operations' 2012 natural gas utility operating sales revenues by jurisdiction is as follows: Idaho – 33 percent; Washington – 27 percent; North Dakota – 12 percent; Oregon – 9 percent; Montana – 8 percent; South Dakota – 6 percent; Minnesota – 3 percent; and Wyoming – 2 percent. The natural gas distribution operations are subject to regulation by the IPUC, MNPUC, MTPSC, NDPSC, OPUC, SDPUC, WUTC and WYPSC regarding retail rates, service, accounting and certain security issuances.

System Supply, System Demand and Competition The natural gas distribution operations serve retail natural gas markets, consisting principally of residential and firm commercial space and water heating users, in portions of Idaho, including Boise, Nampa, Twin Falls, Pocatello and Idaho Falls; western Minnesota, including Fergus Falls, Marshall and Crookston; eastern Montana, including Billings, Glendive and Miles City; North Dakota, including Bismarck, Mandan, Dickinson, Wahpeton, Williston, Minot and Jamestown; central and eastern Oregon, including Bend and Pendleton; western and north-central South Dakota, including Rapid City, Pierre, Spearfish and Mobridge; western, southeastern and south-central Washington, including Bellingham, Bremerton, Longview, Moses Lake, Mount Vernon, Tri-Cities, Walla Walla and Yakima; and northern Wyoming, including Sheridan. These markets are highly seasonal and sales volumes depend largely on the weather, the effects of which are mitigated in certain jurisdictions by a weather normalization mechanism discussed in Regulatory Matters. In addition to the residential and commercial sales, the utilities transport natural gas for larger commercial and industrial customers who purchase their own supply of natural gas.

Competition in varying degrees exists between natural gas and other fuels and forms of energy. The natural gas distribution operations have established various natural gas transportation service rates for their distribution businesses to retain interruptible commercial and industrial loads. These services have enhanced the natural gas distribution operations' competitive posture with alternative fuels, although certain customers have bypassed the distribution systems by directly accessing transmission pipelines within close proximity. These bypasses did not have a material effect on results of operations.

The natural gas distribution operations and various distribution transportation customers obtain their system requirements directly from producers, processors and marketers. The Company's purchased natural gas is supplied by a portfolio of contracts specifying market-based pricing and is transported under transportation agreements with WBI Energy Transmission, Northwest Pipeline GP, Northern Natural Gas, Gas Transmission Northwest LLC, Northwestern Energy, Viking Gas Transmission Company and Ruby Pipeline LLC. The natural gas distribution operations have contracts for storage services to provide gas supply during the winter heating season and to meet peak day demand with various storage providers, including WBI Energy Transmission, Questar Pipeline Company, Northwest Pipeline GP and Northern Natural Gas. In addition, certain of the operations have entered into natural gas supply management agreements with various parties. Demand for natural gas, which is a widely traded commodity, has historically been sensitive to seasonal heating and industrial load requirements as well as changes in market price. The natural gas distribution operations believe that, based on current and projected domestic and regional supplies of natural gas and the pipeline transmission network currently available through their suppliers and pipeline service providers, supplies are adequate to meet their system natural gas requirements for the next decade.

Regulatory Matters The natural gas distribution operations' retail natural gas rate schedules contain clauses permitting adjustments in rates based upon changes in natural gas commodity, transportation and storage costs. Current tariffs allow for recovery or refunds of under- or over-recovered gas costs within a period ranging from 12 to 28 months.

Montana-Dakota's North Dakota and South Dakota natural gas tariffs contain weather normalization mechanisms applicable to firm customers that adjust the distribution delivery charge revenues to reflect weather fluctuations during the November 1 through May 1 billing periods.

Cascade filed an application for a decoupling mechanism with the OPUC. The OPUC approved an extension until April 30, 2013, of Cascade's existing decoupling mechanism, which was scheduled to expire in the third quarter of 2012. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

For information on regulatory matters, see Item 8 – Note 18.

Environmental Matters The natural gas distribution operations are subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. The natural gas distribution operations believe they are in substantial compliance with those regulations.

The Company's natural gas distribution operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the RCRA. Certain of the natural gas distribution operations routinely handle PCBs from their natural gas operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required. Capital and operational expenditures for natural gas distribution operations could be affected in a variety of ways by potential new GHG legislation or regulation. In particular, such legislation or regulation would likely increase capital expenditures for energy efficiency and conservation programs and operational costs associated with GHG emissions compliance. Natural gas distribution operations expect to recover the operational and capital expenditures for GHG regulatory compliance in rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

In 2012, the natural gas distribution operations accrued $6.7 million for a remedial investigation and a feasibility study for a former manufactured gas plant in Washington. The natural gas distribution operations did not incur any other material environmental expenditures in 2012. Except as to what may be ultimately determined with regard to the issues described later, the natural gas distribution operations do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2015.

Montana-Dakota has had an economic interest in four historic manufactured gas plants and Great Plains has had an economic interest in one historic manufactured gas plant within their service territories, none of which are currently being actively investigated, and for which any remediation expenses are not expected to be material. Cascade has had an economic interest in nine former manufactured gas plants within its service territory. Cascade has been involved in the investigation and remediation of manufactured gas plants in Washington and Oregon. In addition, Cascade received a third party claim notice in 2008 for one additional site in Washington. See Item 8 – Note 19 for a further discussion of these three manufactured gas plants. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

Pipeline and Energy Services

General WBI Energy Transmission, the regulated business of this segment, owns and operates approximately 3,800 miles of transmission, gathering and storage lines in Montana, North Dakota, South Dakota and Wyoming. Three underground storage fields in Montana and Wyoming provide storage services to local distribution companies, producers, natural gas marketers and others, and serve to enhance system deliverability. WBI Energy Transmission's system is strategically located near five natural gas producing basins, making natural gas supplies available to WBI Energy Transmission's transportation and storage customers. The system has 13 interconnecting points with other pipeline facilities allowing for the receipt and/or delivery of natural gas to and from other regions of the country and from Canada. At December 31, 2012, WBI Energy Transmission's net plant investment was $337.7 million. Under the Natural Gas Act, as amended, WBI Energy Transmission is subject to the jurisdiction of the FERC regarding certificate, rate, service and accounting matters.

WBI Energy Midstream, the nonregulated pipeline business of this segment, owns and operates gathering facilities in Colorado, Kansas, Montana and Wyoming. It also owns a 50 percent undivided interest in certain midstream assets located in western North Dakota that were acquired in 2012, which include a natural gas processing plant, both oil and gas gathering pipelines, an oil storage terminal and an oil pipeline. In total, facilities include approximately 1,700 miles of operated field gathering lines, some of which interconnect with WBI Energy Transmission's system. WBI Energy Midstream provides natural gas and oil gathering services, natural gas processing and a variety of other energy-related services, including cathodic protection, water hauling, contract compression operations, measurement services, and energy efficiency product sales and installation services to large end-users.

Prairielands, an energy services business, provides natural gas purchase and sales services to local distribution companies, producers, other marketers and a limited number of large end-users, primarily using natural gas produced by the Company's exploration and production segment. Certain of the services are provided based on contracts that call for a determinable quantity of natural gas. At December 31, 2012, Prairielands has commitments to deliver fixed and determinable amounts of natural gas under these contracts of 3.4 Bcf in 2013 and the commitments to deliver natural gas for years subsequent to 2013 are immaterial. The Company currently estimates that it can adequately meet the requirements of these contracts based upon the estimated natural gas production and reserves of Fidelity.

A majority of its pipeline and energy services business is transacted in the northern Great Plains and Rocky Mountain regions of the United States.

For information regarding natural gas gathering operations litigation, see Item 8 – Note 19.

System Demand and Competition WBI Energy Transmission competes with several pipelines for its customers' transportation, storage and gathering business and at times may discount rates in an effort to retain market share. However, the strategic location of WBI Energy Transmission's system near five natural gas producing basins and the availability of underground storage and gathering services provided by WBI Energy Transmission and affiliates, along with interconnections with other pipelines, serve to enhance WBI Energy Transmission's competitive position.

Although certain of WBI Energy Transmission's firm customers, including its largest firm customer Montana-Dakota, serve relatively secure residential and commercial end-users, they generally all have some price-sensitive end-users that could switch to alternate fuels.

WBI Energy Transmission transports substantially all of Montana-Dakota's natural gas, primarily utilizing firm transportation agreements, which for the year ended December 31, 2012, represented 46 percent of WBI Energy Transmission's subscribed firm transportation contract demand. The majority of the firm transportation agreements with Montana-Dakota expire in June 2017. In addition, Montana-Dakota has a contract with WBI Energy Transmission to provide firm storage services to facilitate meeting Montana-Dakota's winter peak requirements expiring in July 2015.

WBI Energy Midstream competes with several midstream companies for existing customers, for the expansion of its systems and for the installation of new systems. WBI Energy Midstream's strong position in the fields in which it operates, its focus on customer service and the variety of services it offers, along with its interconnection with various other pipelines, serve to enhance its competitive position.

System Supply Natural gas supplies emanate from traditional and nontraditional production activities in the region and from off-system supply sources. While certain traditional regional supply sources are in various stages of decline, incremental supply from nontraditional sources have been developed which has helped support WBI Energy Transmission's supply needs. This includes new natural gas supply associated with the continued development of the Bakken area in Montana and North Dakota. The Powder River Basin also provides a nontraditional natural gas supply to the WBI Energy Transmission system. In addition, off-system supply sources are available through the Company's interconnections with other pipeline systems. WBI Energy Transmission expects to facilitate the movement of these supplies by making available its transportation and storage services. WBI Energy Transmission will continue to look for opportunities to increase transportation, gathering and storage services through system expansion and/or other pipeline interconnections or enhancements that could provide substantial future benefits.

WBI Energy Transmission's underground natural gas storage facilities have a certificated storage capacity of approximately 353 Bcf, including 193 Bcf of working gas capacity, 85 Bcf of cushion gas and 75 Bcf of native gas. WBI Energy Transmission's storage facilities enable its customers to purchase natural gas at more uniform daily volumes throughout the year and meet winter peak requirements.

Environmental Matters The pipeline and energy services operations are generally subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. The Company believes it is in substantial compliance with those regulations.

Ongoing operations are subject to the Clean Air Act, the Clean Water Act, the NEPA and other state and federal regulations. Administration of many provisions of these laws has been delegated to the states where WBI Energy Transmission and WBI Energy Midstream operate. Permit terms vary and all permits carry operational compliance conditions. Some permits require annual renewal, some have terms ranging from one to five years and others have no expiration date. Permits are renewed and modified, as necessary, based on defined permit expiration dates, operational demand and/or regulatory changes.

Detailed environmental assessments and/or environmental impact statements are included in the FERC's permitting processes for both the construction and abandonment of WBI Energy Transmission's natural gas transmission pipelines, compressor stations and storage facilities.

The pipeline and energy services operations did not incur any material environmental expenditures in 2012 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2015.

Exploration and Production

General Fidelity is involved in the acquisition, exploration, development and production of oil and natural gas resources. Fidelity continues to seek additional reserve and production growth opportunities through these activities. Future growth is dependent upon its success in these endeavors. Fidelity shares revenues and expenses from the development of specified properties in proportion to its ownership interests.

Fidelity's business is focused primarily in two core regions: Rocky Mountain and Mid-Continent/Gulf States.

Rocky Mountain

Fidelity's Rocky Mountain region includes the following significant operating areas:

- Bakken areas – Oil targets in which Fidelity holds approximately 16,000 net acres in Mountrail County, North Dakota, approximately 51,000 net acres in Stark County, North Dakota, and approximately 60,000 net acres in Richland County, Montana.
- Cedar Creek Anticline – Primarily in eastern Montana, the Company has a long-held net profits interest in this oil play.
- Paradox Basin – The Company holds approximately 83,000 net acres located in Grand and San Juan Counties, Utah, targeting oil.
- Big Horn Basin – These interests include approximately 33,000 net acres in Wyoming, targeting oil and NGL.
- Green River Basin – These properties are primarily natural gas targets in Wyoming in which the Company holds approximately 36,000 net acres.
- Baker Field – Long-held natural gas properties in which Fidelity holds approximately 99,000 net acres in southeastern Montana and southwestern North Dakota.
- Bowdoin Field – Long-held natural gas properties in which Fidelity holds approximately 127,000 net acres in north-central Montana.
- Other – Includes other exploratory oil projects in the Niobrara play in Wyoming and the Heath Shale in Montana; along with the Powder River Basin natural gas properties, which Fidelity is pursuing divestment of; and various non-operated positions.

Mid-Continent/Gulf States

Fidelity's Mid-Continent/Gulf States region includes the following significant operating areas:

- South Texas – This area includes approximately 9,000 net acres in the Tabasco, Texan Gardens and Flores fields. This area has significant NGL content associated with the natural gas.
- East/Central Texas – Fidelity holds approximately 27,000 net acres, primarily natural gas and associated NGL.
- Other – Includes various non-operated onshore interests, as well as offshore interests in the shallow waters off the coasts of Texas and Louisiana.

Operating Information Annual net production by region for 2012 was as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total
Rocky Mountain	3,295	249	23,180	7,408	74%
Mid-Continent/Gulf States	399	579	10,034	2,650	26
Total	3,694	828	33,214	10,058	100%

Note: Bakken-Mountrail County represents 47% of total annual net oil production and is the only field that contains 15 percent or more of the Company's total proved reserves as of December 31, 2012.

Annual net production by region for 2011 was as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total
Rocky Mountain	2,290	199	34,472	8,234	74%
Mid-Continent/Gulf States	434	577	11,126	2,865	26
Total	2,724	776	45,598	11,099	100%

Note: There are no fields that contain 15 percent or more of the Company's total proved reserves as of December 31, 2011.

Annual net production by region for 2010 was as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total
Rocky Mountain	2,236	129	39,160	8,892	76%
Mid-Continent/Gulf States	531	366	11,231	2,769	24
Total	2,767	495	50,391	11,661	100%

Note: Baker field and Bowdoin field represent 28 percent and 20 percent, respectively, of total annual net natural gas production, and are the only fields that contain 15 percent or more of the Company's total proved reserves as of December 31, 2010.

Well and Acreage Information Gross and net productive well counts and gross and net developed and undeveloped acreage related to Fidelity's interests at December 31, 2012, were as follows:

	Gross*	Net**
Productive wells:		
Oil	1,191	266
Natural gas	2,296	1,571
Total	3,487	1,837
Developed acreage (000's)	635	381
Undeveloped acreage set to expire in the years (000's):		
2013	42	27
2014	108	76
2015	242	154
Thereafter	626	319
Total undeveloped acreage	1,018	576

* Reflects well or acreage in which an interest is owned.
** Reflects Fidelity's percentage of ownership.

In most cases, acreage set to expire can be held through drilling operations or the Company can exercise extension options.

Delivery Commitments At December 31, 2012, Fidelity has commitments to deliver fixed and determinable amounts of natural gas under contracts of 855,000 Mcf in 2013 and the commitments to deliver natural gas for years subsequent to 2013 are immaterial. Fidelity does not have any material delivery commitments to deliver fixed and determinable amounts of oil at December 31, 2012.

Exploratory and Development Wells The following table reflects activities related to Fidelity's oil and natural gas wells drilled and/or tested during 2012, 2011 and 2010:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2012	**24**	**3**	**27**	**39**	**1**	**40**	**67**
2011	4	–	4	48	–	48	52
2010	3	4	7	133	1	134	141

At December 31, 2012, there were 44 gross (17 net) wells in the process of drilling or under evaluation, 39 of which were development wells and 5 of which were exploratory wells. These wells are not included in the previous table. Fidelity expects to complete the drilling and testing of these wells within the next 12 months.

The information in the preceding table should not be considered indicative of future performance nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons whether or not they produce a reasonable rate of return.

Competition The exploration and production industry is highly competitive. Fidelity competes with a substantial number of major and independent exploration and production companies in acquiring producing properties and new leases for future exploration and development, and in securing the equipment, services and expertise necessary to explore, develop and operate its properties.

Environmental Matters Fidelity's exploration and production operations are generally subject to federal, state and local environmental and operational laws and regulations. Fidelity believes it is in substantial compliance with these regulations.

The ongoing operations of Fidelity are subject to the Clean Air Act, the Clean Water Act, the NEPA, ESA and other state, federal and local regulations. Administration of many provisions of these laws has been delegated to the states where Fidelity operates. Permit terms vary and all permits carry operational compliance conditions. Some permits require annual renewal, some have terms ranging from one to five years and others have no expiration date. Permits are renewed and modified, as necessary, based on defined permit expiration dates, operational demand and/or regulatory changes.

Detailed environmental assessments and/or environmental impact statements under federal and state laws are required as part of the permitting process covering the conduct of drilling and production operations as well as in the abandonment and reclamation of facilities.

In connection with production operations, Fidelity has not incurred any material capital environmental expenditures in 2012 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2015.

Proved Reserve Information Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. Other factors used in the proved reserve estimates are prices, market differentials, estimates of well operating and future development costs, taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

The proved reserve estimates are prepared by internal engineers assigned to an asset team by geographic area. Senior management reviews and approves the reserve estimates to ensure they are materially accurate. The technical person responsible for overseeing the preparation of the reserve estimates holds a bachelor of science degree in geological engineering and a master of science degree in geology, has 30 years experience in petroleum engineering and reserve estimation, and is a member of multiple professional organizations. In addition, the Company engages an independent third party to audit its proved reserves. Ryder Scott reviewed the Company's proved reserve quantity estimates as of December 31, 2012. The technical person at Ryder Scott primarily responsible for overseeing the reserves audit is a Senior Vice President with over 30 years of experience in estimating and auditing reserves attributable to oil and gas properties, holds a bachelor of science degree in mechanical engineering, is a registered professional engineer, and is a member of multiple professional organizations.

Fidelity's proved reserves by region at December 31, 2012, are as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total	PV-10 Value* (in millions)
Rocky Mountain	31,387	2,586	161,765	60,934	76%	$ 902.1
Mid-Continent/Gulf States	2,066	4,567	77,513	19,552	24	160.9
Total proved reserves	33,453	7,153	239,278	80,486	100%	1,063.0
Discounted future income taxes						179.6
Standardized measure of discounted future net cash flows relating to proved reserves						$ 883.4

* Pre-tax PV-10 value is a non-GAAP financial measure that is derived from the most directly comparable GAAP financial measure which is the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows disclosed in Item 8 – Supplementary Financial Information, is presented after deducting discounted future income taxes, whereas the PV-10 value is presented before income taxes. Pre-tax PV-10 value is commonly used by the Company to evaluate properties that are acquired and sold and to assess the potential return on investment in the Company's oil and natural gas properties. The Company believes pre-tax PV-10 value is a useful supplemental disclosure to the standardized measure as the Company believes readers may utilize this value as a basis for comparison of the relative size and value of the Company's reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. However, pre-tax PV-10 value is not a substitute for the standardized measure of discounted future net cash flows. Neither the Company's pre-tax PV-10 value nor the standardized measure of discounted future net cash flows purports to represent the fair value of the Company's oil and natural gas properties.

For additional information related to oil and natural gas interests, see Item 8 – Note 1 and Supplementary Financial Information.

Construction Materials and Contracting

General Knife River operates construction materials and contracting businesses headquartered in Alaska, California, Hawaii, Idaho, Iowa, Minnesota, Montana, North Dakota, Oregon, Texas, Washington and Wyoming. These operations mine, process and sell construction aggregates (crushed stone, sand and gravel); produce and sell asphalt mix and supply ready-mixed concrete for use in most types of construction, including roads, freeways and bridges, as well as homes, schools, shopping centers, office buildings and industrial parks. Although not common to all locations, other products include the sale of cement, liquid asphalt for various commercial and roadway applications, various finished concrete products and other building materials and related contracting services.

For information regarding construction materials litigation, see Item 8 – Note 19.

The construction materials business had approximately $406 million in backlog at December 31, 2012, compared to $384 million at December 31, 2011. The Company anticipates that a significant amount of the current backlog will be completed during the year ending December 31, 2013.

Competition Knife River's construction materials products are marketed under highly competitive conditions. Price is the principal competitive force to which these products are subject, with service, quality, delivery time and proximity to the customer also being significant factors. The number and size of competitors varies in each of Knife River's principal market areas and product lines.

The demand for construction materials products is significantly influenced by the cyclical nature of the construction industry in general. In addition, construction materials activity in certain locations may be seasonal in nature due to the effects of weather. The key economic factors affecting product demand are changes in the level of local, state and federal governmental spending, general economic conditions within the market area that influence both the commercial and private sectors, and prevailing interest rates.

Knife River is not dependent on any single customer or group of customers for sales of its products and services, the loss of which would have a material adverse effect on its construction materials businesses.

Reserve Information Reserve estimates are calculated based on the best available data. This data is collected from drill holes and other subsurface investigations, as well as investigations of surface features such as mine high walls and other exposures of the aggregate reserves. Mine plans, production history and geologic data also are utilized to estimate reserve quantities. Most acquisitions are made of mature businesses with established reserves, as distinguished from exploratory-type properties.

Estimates are based on analyses of the data described above by experienced internal mining engineers, operating personnel and geologists. Property setbacks and other regulatory restrictions and limitations are identified to determine the total area available for mining. Data described previously are used to calculate the thickness of aggregate materials to be recovered. Topography associated with alluvial sand and gravel deposits is typically flat and volumes of these materials are calculated by applying the thickness of the resource over the areas available for mining. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 1.5 tons per cubic yard in the ground is used for sand and gravel deposits.

Topography associated with the hard rock reserves is typically much more diverse. Therefore, using available data, a final topography map is created and computer software is utilized to compute the volumes between the existing and final topographies. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 2 tons per cubic yard in the ground is used for hard rock quarries.

Estimated reserves are probable reserves as defined in Securities Act Industry Guide 7. Remaining reserves are based on estimates of volumes that can be economically extracted and sold to meet current market and product applications. The reserve estimates include only salable tonnage and thus exclude waste materials that are generated in the crushing and processing phases of the operation. Approximately 1.0 billion tons of the 1.1 billion tons of aggregate reserves are permitted reserves. The remaining reserves are on properties that are expected to be permitted for mining under current regulatory requirements. The data used to calculate the remaining reserves may require revisions in the future to account for changes in customer requirements and unknown geological occurrences. The years remaining were calculated by dividing remaining reserves by the three-year average sales from 2010 through 2012. Actual useful lives of these reserves will be subject to, among other things, fluctuations in customer demand, customer specifications, geological conditions and changes in mining plans.

The following table sets forth details applicable to the Company's aggregate reserves under ownership or lease as of December 31, 2012, and sales for the years ended December 31, 2012, 2011 and 2010:

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)			Estimated Reserves	Lease	Reserve Life
Production Area	owned	leased	owned	leased	**2012**	2011	2010	(000's tons)	Expiration	(years)
Anchorage, AK	–	–	1	–	**110**	137	854	19,953	N/A	54
Hawaii	–	6	–	–	**1,678**	1,527	1,412	59,005	2017-2064	38
Northern CA	–	–	9	1	**1,203**	1,552	1,043	47,095	2014	37
Southern CA	–	2	–	–	**784**	1,134	619	92,351	2035	Over 100
Portland, OR	1	3	5	3	**2,698**	3,106	2,521	239,917	2014-2055	86
Eugene, OR	3	4	4	1	**847**	884	1,311	169,217	2013-2046	Over 100
Central OR/WA/ID	1	2	4	4	**1,131**	851	1,192	104,658	2015-2077	99
Southwest OR	5	4	11	6	**1,613**	1,604	1,505	98,071	2013-2053	62
Central MT	–	–	1	2	**1,200**	758	971	29,129	2013-2027	30
Northwest MT	–	–	7	2	**1,011**	1,370	1,362	67,193	2016-2020	54
Wyoming	–	–	1	2	**428**	461	447	12,705	2013-2019	29
Central MN	–	1	37	24	**1,714**	1,520	1,527	74,922	2013-2028	47
Northern MN	2	–	16	5	**195**	355	401	27,023	2013-2017	85
ND/SD	–	–	4	15	**1,711**	1,727	1,106	28,780	2013-2031	19
Iowa	–	1	–	1	**305**	249	642	5,457	2017	14
Texas	1	1	1	–	**692**	1,182	1,648	12,760	2022	11
Sales from other sources					**5,965**	6,319	4,788			
					23,285	24,736	23,349	1,088,236		

The 1.1 billion tons of estimated aggregate reserves at December 31, 2012, are comprised of 489 million tons that are owned and 599 million tons that are leased. Approximately 49 percent of the tons under lease have lease expiration dates of 20 years or more. The weighted average years remaining on all leases containing estimated probable aggregate reserves is approximately 24 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2010 through 2012 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 65 years. Some sites have leases that expire prior to the exhaustion of the estimated reserves. The estimated reserve life assumes, based on Knife River's experience, that leases will be renewed to allow sufficient time to fully recover these reserves.

The changes in Knife River's aggregate reserves for the years ended December 31 are as follows:

	2012	2011	2010
		(000's of tons)	
Aggregate reserves:			
Beginning of year	**1,088,833**	1,107,396	1,125,491
Acquisitions	**950**	1,200	3,600
Sales volumes*	**(17,320)**	(18,417)	(18,561)
Other**	**15,773**	(1,346)	(3,134)
End of year	**1,088,236**	1,088,833	1,107,396

* Excludes sales from other sources.
** Includes property sales and revisions of previous estimates.

Environmental Matters Knife River's construction materials and contracting operations are subject to regulation customary for such operations, including federal, state and local environmental compliance and reclamation regulations. Except as to the issues described later, Knife River believes it is in substantial compliance with these regulations. Individual permits applicable to Knife River's various operations are managed largely by local operations, particularly as they relate to application, modification, renewal, compliance and reporting procedures.

Knife River's asphalt and ready-mixed concrete manufacturing plants and aggregate processing plants are subject to Clean Air Act and Clean Water Act requirements for controlling air emissions and water discharges. Some mining and construction activities also are subject to these laws. In most of the states where Knife River operates, these regulatory programs have been delegated to state and local regulatory authorities. Knife River's facilities also are subject to RCRA as it applies to the management of hazardous wastes and underground storage tank systems. These programs also have generally been delegated to the state and local authorities in the states where Knife River operates. Knife River's facilities must comply with requirements for managing wastes and underground storage tank systems.

Some Knife River activities are directly regulated by federal agencies. For example, certain in-water mining operations are subject to provisions of the Clean Water Act that are administered by the Army Corps. Knife River operates several such operations, including gravel bar skimming and dredging operations, and Knife River has the associated permits as required. The expiration dates of these permits vary, with five years generally being the longest term.

Knife River's operations also are occasionally subject to the ESA. For example, land use regulations often require environmental studies, including wildlife studies, before a permit may be granted for a new or expanded mining facility or an asphalt or concrete plant. If endangered species or their habitats are identified, ESA requirements for protection, mitigation or avoidance apply. Endangered species protection requirements are usually included as part of land use permit conditions. Typical conditions include avoidance, setbacks, restrictions on operations during certain times of the breeding or rearing season, and construction or purchase of mitigation habitat. Knife River's operations also are subject to state and federal cultural resources protection laws when new areas are disturbed for mining operations or processing plants. Land use permit applications generally require that areas proposed for mining or other surface disturbances be surveyed for cultural resources. If any are identified, they must be protected or managed in accordance with regulatory agency requirements.

The most comprehensive environmental permit requirements are usually associated with new mining operations, although requirements vary widely from state to state and even within states. In some areas, land use regulations and associated permitting requirements are minimal. However, some states and local jurisdictions have very demanding requirements for permitting new mines. Environmental impact reports are sometimes required before a mining permit application can even be considered for approval. These reports can take up to several years to complete. The report can include projected impacts of the proposed project on air and water quality, wildlife, noise levels, traffic, scenic vistas and other environmental factors. The reports generally include suggested actions to mitigate the projected adverse impacts.

Provisions for public hearings and public comments are usually included in land use permit application review procedures in the counties where Knife River operates. After taking into account environmental, mine plan and reclamation information provided by the permittee as well as comments from the public and other regulatory agencies, the local authority approves or denies the permit application. Denial is rare, but land use permits often include conditions that must be addressed by the permittee. Conditions may include property line setbacks, reclamation requirements, environmental monitoring and reporting, operating hour restrictions, financial guarantees for reclamation, and other requirements intended to protect the environment or address concerns submitted by the public or other regulatory agencies.

Knife River has been successful in obtaining mining and other land use permit approvals so that sufficient permitted reserves are available to support its operations. For mining operations, this often requires considerable advanced planning to ensure sufficient time is available to complete the permitting process before the newly permitted aggregate reserve is needed to support Knife River's operations.

Knife River's Gascoyne surface coal mine last produced coal in 1995 but continues to be subject to reclamation requirements of the SMCRA, as well as the North Dakota Surface Mining Act. Portions of the Gascoyne Mine remain under reclamation bond until the 10-year revegetation liability period has expired. A portion of the original permit has been released from bond and additional areas are currently in the process of having the bond released. Knife River's intention is to request bond release as soon as it is deemed possible with all final bond release applications being filed by 2016.

Knife River did not incur any material environmental expenditures in 2012 and, except as to what may be ultimately determined with regard to the issues described later, Knife River does not expect to incur any material expenditures related to environmental compliance with current laws and regulations through 2015.

In December 2000, Knife River – Northwest was named by the EPA as a PRP in connection with the cleanup of a commercial property site, acquired by Knife River – Northwest in 1999, and part of the Portland, Oregon, Harbor Superfund Site. For additional information, see Item 8 – Note 19.

The State of Hawaii Department of Health issued a Notice of Violation to Hawaiian Cement dated August 31, 2012, alleging violations of Hawaii's Water Pollution statute. For additional information, see Item 8 – Note 19.

Mine Safety The Dodd-Frank Act requires disclosure of certain mine safety information. For additional information, see Item 4 – Mine Safety Disclosures.

Construction Services

General MDU Construction Services specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes specialty equipment. These services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

Construction and maintenance crews are active year round. However, activity in certain locations may be seasonal in nature due to the effects of weather.

MDU Construction Services operates a fleet of owned and leased trucks and trailers, support vehicles and specialty construction equipment, such as backhoes, excavators, trenchers, generators, boring machines and cranes. In addition, as of December 31, 2012, MDU Construction Services owned or leased facilities in 17 states. This space is used for offices, equipment yards, warehousing, storage and vehicle shops.

MDU Construction Services' backlog is comprised of the uncompleted portion of services to be performed under job-specific contracts. The backlog at December 31, 2012, was approximately $325 million compared to $308 million at December 31, 2011. MDU Construction Services expects to complete a significant amount of this backlog during the year ending December 31, 2013. Due to the nature of its contractual arrangements, in many instances MDU Construction Services' customers are not committed to the specific volumes of services to be purchased under a contract, but rather MDU Construction Services is committed to perform these services if and to the extent requested by the customer. Therefore, there can be no assurance as to the customers' requirements during a particular period or that such estimates at any point in time are predictive of future revenues.

MDU Construction Services works with the National Electrical Contractors Association, the IBEW and other trade associations on hiring and recruiting a qualified workforce.

Competition MDU Construction Services operates in a highly competitive business environment. Most of MDU Construction Services' work is obtained on the basis of competitive bids or by negotiation of either cost-plus or fixed-price contracts. The workforce and equipment are highly mobile, providing greater flexibility in the size and location of MDU Construction Services' market area. Competition is based primarily on price and reputation for quality, safety and reliability. The size and location of the services provided, as well as the state of the economy, will be factors in the number of competitors that MDU Construction Services will encounter on any particular project. MDU Construction Services believes that the diversification of the services it provides, the markets it serves throughout the United States and the management of its workforce will enable it to effectively operate in this competitive environment.

Utilities and independent contractors represent the largest customer base for this segment. Accordingly, utility and subcontract work accounts for a significant portion of the work performed by MDU Construction Services and the amount of construction contracts is dependent to a certain extent on the level and timing of maintenance and construction programs undertaken by customers. MDU Construction Services relies on repeat customers and strives to maintain successful long-term relationships with these customers.

Environmental Matters MDU Construction Services' operations are subject to regulation customary for the industry, including federal, state and local environmental compliance. MDU Construction Services believes it is in substantial compliance with these regulations.

The nature of MDU Construction Services' operations is such that few, if any, environmental permits are required. Operational convenience supports the use of petroleum storage tanks in several locations, which are permitted under state programs authorized by the EPA. MDU Construction Services has no ongoing remediation related to releases from petroleum storage tanks. MDU Construction Services' operations are conditionally exempt small-quantity waste generators, subject to minimal regulation under the RCRA. Federal permits for specific construction and maintenance jobs that may require these permits are typically obtained by the hiring entity, and not by MDU Construction Services.

MDU Construction Services did not incur any material environmental expenditures in 2012 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2015.

Item 1A. Risk Factors

The Company's business and financial results are subject to a number of risks and uncertainties, including those set forth below and in other documents that it files with the SEC. The factors and the other matters discussed herein are important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

Economic Risks

The Company's exploration and production and pipeline and energy services businesses are dependent on factors, including commodity prices and commodity price basis differentials, that are subject to various external influences that cannot be controlled.

These factors include: fluctuations in oil, NGL and natural gas production and prices; fluctuations in commodity price basis differentials; availability of economic supplies of natural gas; drilling successes in oil and natural gas operations; the timely receipt of necessary permits and approvals; the ability to contract for or to secure necessary drilling rig and service contracts and to retain employees to identify, drill for and develop reserves; the ability to acquire oil and natural gas properties; and other risks incidental to the development and operations of oil and natural gas wells, processing plants and pipeline systems. Volatility in oil, NGL and natural gas prices could negatively affect the results of operations, cash flows and asset values of the Company's exploration and production and pipeline and energy services businesses.

The regulatory approval, permitting, construction, startup and operation of power generation facilities may involve unanticipated changes or delays that could negatively impact the Company's business and its results of operations and cash flows.

The construction, startup and operation of power generation facilities involves many risks, including: delays; breakdown or failure of equipment; inability to obtain required governmental permits and approvals; inability to negotiate acceptable acquisition, construction, fuel supply, off-take, transmission or other material agreements; changes in market price for power; cost increases; as well as the risk of performance below expected levels of output or efficiency. Such unanticipated events could negatively impact the Company's business, its results of operations and cash flows.

Economic volatility affects the Company's operations, as well as the demand for its products and services and the value of its investments and investment returns including its pension and other postretirement benefit plans, and may have a negative impact on the Company's future revenues and cash flows.

The global demand for natural resources, interest rates, governmental budget constraints and the ongoing threat of terrorism can create volatility in the financial markets. Current economic conditions have negatively affected the level of public and private expenditures on projects and the timing of these projects which, in turn, has negatively affected the demand for the Company's products and services, primarily at the Company's construction businesses. The level of demand for construction products and services could continue to be adversely impacted by the economic conditions in the industries the Company serves, as well as in the economy in general. State and federal budget issues may continue to negatively affect the funding available for infrastructure spending. This continued economic volatility could have a material adverse effect on the Company's results of operations, cash flows and asset values.

Changing market conditions could negatively affect the market value of assets held in the Company's pension and other postretirement benefit plans and may increase the amount and accelerate the timing of required funding contributions.

The Company relies on financing sources and capital markets. Access to these markets may be adversely affected by factors beyond the Company's control. If the Company is unable to obtain economic financing in the future, the Company's ability to execute its business plans, make capital expenditures or pursue acquisitions that the Company may otherwise rely on for future growth could be impaired. As a result, the market value of the Company's common stock may be adversely affected. If the Company issues a substantial amount of common stock it could have a dilutive effect on its existing shareholders.

The Company relies on access to both short-term borrowings, including the issuance of commercial paper, and long-term capital markets as sources of liquidity for capital requirements not satisfied by its cash flow from operations. If the Company is not able to access capital at competitive rates, the ability to implement its business plans may be adversely affected. Market disruptions or a downgrade of the Company's credit ratings may increase the cost of borrowing or adversely affect its ability to access one or more financial markets. Such disruptions could include:

- A severe prolonged economic downturn
- The bankruptcy of unrelated industry leaders in the same line of business
- Deterioration in capital market conditions
- Turmoil in the financial services industry
- Volatility in commodity prices
- Terrorist attacks
- Cyber attacks

Economic turmoil, market disruptions and volatility in the securities trading markets, as well as other factors including changes in the Company's results of operations, financial position and prospects, may adversely affect the market price of the Company's common stock.

The Company currently has a shelf registration statement on file with the SEC, under which the Company may issue and sell any combination of common stock and debt securities. The issuance of a substantial amount of the Company's common stock, whether sold pursuant to the registration statement, issued in connection with an acquisition or otherwise issued, or the perception that such an issuance could occur, may adversely affect the market price of the Company's common stock.

The Company is exposed to credit risk and the risk of loss resulting from the nonpayment and/or nonperformance by the Company's customers and counterparties.

If any of the Company's customers or counterparties were to experience financial difficulties or file for bankruptcy, the Company could experience difficulty in collecting receivables. The nonpayment and/or nonperformance by the Company's customers and counterparties could have a negative impact on the Company's results of operations and cash flows.

The backlogs at the Company's construction materials and contracting and construction services businesses are subject to delay or cancellation and may not be realized.

Backlog consists of the uncompleted portion of services to be performed under job-specific contracts. Contracts are subject to delay, default or cancellation and the contracts in the Company's backlog are subject to changes in the scope of services to be provided as well as adjustments to the costs relating to the applicable contracts. Backlog may also be affected by project delays or cancellations resulting from weather conditions, external market factors and economic factors beyond the Company's control, including the current economic slowdown. Accordingly, there is no assurance that backlog will be realized.

Actual quantities of recoverable oil, NGL and natural gas reserves and discounted future net cash flows from those reserves may vary significantly from estimated amounts. There is a risk that changes in estimates of proved reserve quantities or other factors including downward movements in prices, could result in additional future noncash write-downs of the Company's oil and natural gas properties.

The process of estimating oil, NGL and natural gas reserves is complex. Reserve estimates are based on assumptions relating to oil, NGL and natural gas pricing, drilling and operating expenses, capital expenditures, taxes, timing of operations, and the percentage of interest owned by the Company in the properties. The proved reserve estimates are prepared for each of the Company's properties by internal engineers assigned to an asset team by geographic area. The internal engineers analyze available geological, geophysical, engineering and economic data for each geographic area. The internal engineers make various assumptions regarding this data. The extent, quality and reliability of this data can vary. Although the Company has prepared its proved reserve estimates in accordance with guidelines established by the industry and the SEC, significant changes to the proved reserve estimates may occur based on actual results of production, drilling, costs and pricing.

The Company bases the estimated discounted future net cash flows from proved reserves on prices and current costs in accordance with SEC requirements. Actual future prices and costs may be significantly different. There is risk that lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in additional future noncash write-downs of the Company's oil and natural gas properties.

Environmental and Regulatory Risks

The Company's operations are subject to environmental laws and regulations that may increase costs of operations, impact or limit business plans, or expose the Company to environmental liabilities.

The Company is subject to environmental laws and regulations affecting many aspects of its present and future operations, including air quality, water quality, waste management and other environmental considerations. These laws and regulations can result in increased capital, operating and other costs, delays as a result of litigation and administrative proceedings, and compliance, remediation, containment, monitoring and reporting obligations, particularly with regard to laws relating to electric generation operations and oil and natural gas development. These laws and regulations generally require the Company to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Although the Company strives to comply with all applicable environmental laws and regulations, public and private entities, as well as private individuals, may seek injunctive relief or other remedies to enforce applicable environmental laws and regulations with which they have differing interpretations of the Company's legal or regulatory compliance. The Company cannot predict the outcome (financial or operational) of any related litigation or administrative proceedings that may arise.

Existing environmental laws and regulations may be revised and new laws and regulations seeking to protect the environment may be adopted or become applicable to the Company. These laws and regulations could require the Company to limit the use or output of certain facilities, restrict the use of certain fuels, install pollution control equipment or initiate pollution control technologies, remediate environmental contamination, remove or reduce environmental hazards, or prevent or limit the development of resources. Revised or additional laws and regulations, that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on the Company's results of operations and cash flows.

The EPA has issued draft regulations that outline several possible approaches for coal combustion residuals management under the RCRA. One approach, designating coal ash as a hazardous waste, would significantly change the manner and increase the costs of managing coal ash at five plants that supply electricity to customers of Montana-Dakota. This designation also could significantly increase costs for Knife River, which beneficially uses fly ash as a cement replacement in ready-mixed concrete and road base applications.

In December 2011, the EPA finalized the Mercury and Air Toxics rule that will require reductions in mercury and other toxic air emissions from coal- and oil-fired electric utility steam generating units. Montana-Dakota evaluated the pollution control technologies needed at its electric generation resources to comply with this final rule and determined that a fabric filter baghouse is required to control non-mercury metal emissions at the Lewis & Clark Station near Sidney, Montana. Controls must be installed by April 16, 2015, or April 16, 2016, if a one year extension is granted for installation.

Hydraulic fracturing is an important common practice used by Fidelity that involves injecting water; sand; guar, a water thickening agent; and trace amounts of chemicals under pressure into rock formations to stimulate oil, NGL and natural gas production. Fidelity is following state regulations for well drilling and completion, including regulations related to hydraulic fracturing and disposing of recovered fluids. Fracturing fluid constituents are reported in state or national websites. The EPA is developing a study to review the potential effects of hydraulic fracturing on underground sources of drinking water; the results of that study could impact future legislation or regulation. The BLM has released draft well stimulation regulations for hydraulic fracturing operations. If implemented, the BLM regulations would only affect Fidelity's operations on BLM-administered lands. If adopted as proposed, the BLM regulations, along with other legislative initiatives and regulatory studies, proceedings or initiatives at federal or state agencies that focus on the hydraulic fracturing process, could result in additional compliance, reporting and disclosure requirements. Future legislation or regulation could increase compliance and operating costs, as well as delay or inhibit the Company's ability to develop its oil, NGL and natural gas reserves.

On August 16, 2012, the EPA published a final NSPS rule for the oil and natural gas industry. The NSPS rule phases in over the next two years. The first phase was effective October 15, 2012, and primarily covers natural gas wells that are hydraulically fractured. Under the new rule, gas vapors or emissions from the natural gas wells must be captured or combusted utilizing a high efficiency device. Additional reporting requirements and control devices covering oil and natural gas production equipment will be phased in for certain new oil and gas facilities with a final effective date of January 1, 2015. Impacts on Fidelity, WBI Energy Transmission and WBI Energy Midstream from this new rule are not expected to be material and are likely to include implementation of recordkeeping, reporting and testing requirements and the acquisition and installation of required equipment.

Initiatives to reduce GHG emissions could adversely impact the Company's operations.

Concern that GHG emissions are contributing to global climate change has led to international, federal and state legislative and regulatory proposals to reduce or mitigate the effects of GHG emissions. In late March 2012, the EPA proposed a GHG NSPS for new fossil fuel-fired electric generating units, including coal-fired units and natural gas-fired combined-cycle units. The EPA's new carbon dioxide emissions standard is equivalent to emissions from a natural gas-fired, high-efficiency combined-cycle unit. This stringent standard does not allow for any new coal-fired electric generation to be constructed unless the generating unit's carbon dioxide emissions are captured and sequestered. The EPA has not applied this new standard to existing fossil fuel-fired units or existing units that make modifications, therefore no impacts to Montana-Dakota's existing electric generating facilities are expected. However, it is not clear that the EPA will always exempt required future pollution control project modifications from GHG NSPS. If the EPA does not clearly exempt these projects, the Company's electric generation operations could be adversely impacted.

The primary GHG emitted from the Company's operations is carbon dioxide from combustion of fossil fuels at Montana-Dakota's electric generating facilities, particularly its coal-fired facilities. Approximately 70 percent of Montana-Dakota's owned generating capacity and more than 90 percent of the electricity it generates is from coal-fired facilities. Montana-Dakota also owns approximately 100 MW of natural gas- and oil-fired peaking plants.

The future of GHG regulation remains uncertain. Montana-Dakota's existing electric generating facilities may be subject to GHG laws or regulations within the next few years, including the EPA's proposed GHG NSPS for new fossil fuel-fired units, as well as when the EPA develops any separate GHG NSPS specifically for existing and modified units. Implementation of treaties, legislation or regulations to reduce GHG emissions could affect Montana-Dakota's electric utility operations by requiring expanded energy conservation efforts or increased development of renewable energy sources, as well as other mandates that could significantly increase capital expenditures and operating costs. If Montana-Dakota does not receive timely and full recovery of GHG emission compliance costs from its customers, then such costs could have an adverse impact on the results of its operations.

In addition to Montana-Dakota's electric generation operations, the GHG emissions from the Company's other operations are monitored, analyzed and reported as required in accordance with applicable laws and regulations. The Company monitors the development of GHG regulations and the potential for GHG regulations to impact all existing and future operations.

Due to the uncertain availability of technologies to control GHG emissions and the unknown obligations that potential GHG emission legislation or regulations may create, the Company cannot determine the potential financial impact on its operations.

The Company is subject to government regulations that may delay and/or have a negative impact on its business and its results of operations and cash flows. Statutory and regulatory requirements also may limit another party's ability to acquire the Company.

The Company is subject to regulation or governmental actions by federal, state and local regulatory agencies with respect to, among other things, allowed rates of return and recovery of investment and cost, financing, industry rate structures, health care legislation, tax legislation and recovery of purchased power and purchased gas costs. These governmental regulations significantly influence the Company's operating environment and may affect its ability to recover costs from its customers. The Company is unable to predict the impact on operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on the Company's results of operations and cash flows. Approval from a number of federal and state regulatory agencies would need to be obtained by any potential acquirer of the Company. The approval process could be lengthy and the outcome uncertain.

Other Risks

Weather conditions can adversely affect the Company's operations, and revenues and cash flows.

The Company's results of operations can be affected by changes in the weather. Weather conditions influence the demand for electricity and natural gas, affect the price of energy commodities, affect the ability to perform services at the construction materials and contracting and construction services businesses and affect ongoing operation and maintenance and construction and drilling activities for the pipeline and energy services and exploration and production businesses. In addition, severe weather can be destructive, causing outages, reduced oil and natural gas production, and/or property damage, which could require additional costs to be incurred. As a result, adverse weather conditions could negatively affect the Company's results of operations, financial position and cash flows.

Competition is increasing in all of the Company's businesses.

All of the Company's businesses are subject to increased competition. Construction services' competition is based primarily on price and reputation for quality, safety and reliability. The construction materials products are marketed under highly competitive conditions and are subject to such competitive forces as price, service, delivery time and proximity to the customer. The electric utility and natural gas industries also are experiencing increased competitive pressures as a result of consumer demands, technological advances, volatility in natural gas prices and other factors. Pipeline and energy services competes with several pipelines for access to natural gas supplies and gathering, transportation and storage business. The exploration and production business is subject to competition in the acquisition and development of oil and natural gas properties. The increase in competition could negatively affect the Company's results of operations, financial position and cash flows.

The Company could be subject to limitations on its ability to pay dividends.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on its common stock. Regulatory, contractual and legal limitations, as well as capital requirements and the Company's financial performance or cash flows, could limit the earnings of the Company's divisions and subsidiaries which, in turn, could restrict the Company's ability to pay dividends on its common stock and adversely affect the Company's stock price.

An increase in costs related to obligations under multiemployer pension plans could have a material negative effect on the Company's results of operations and cash flows.

Various operating subsidiaries of the Company participate in approximately 80 multiemployer pension plans for employees represented by certain unions. The Company is required to make contributions to these plans in amounts established under numerous collective bargaining agreements between the operating subsidiaries and those unions.

The Company may be obligated to increase its contributions to underfunded plans that are classified as being in endangered, seriously endangered, or critical status as defined by the Pension Protection Act of 2006. Plans classified as being in one of these statuses are required to adopt RPs or FIPs to improve their funded status through increased contributions, reduced benefits or a combination of the two. Based on available information, the Company believes that approximately 45 percent of the multiemployer plans to which it contributes are currently in endangered, seriously endangered or critical status.

The Company may also be required to increase its contributions to multiemployer plans where the other participating employers in such plans withdraw from the plan and are not able to contribute an amount sufficient to fund the unfunded liabilities associated with their participants in the plans. The amount and timing of any increase in the Company's required contributions to multiemployer pension plans may also depend upon one or more of the following factors including the outcome of collective bargaining, actions taken by trustees who manage the plans, the industry for which contributions are made, future determinations that additional plans reach endangered, seriously endangered or critical status, government regulations and the actual return on assets held in the plans, among others. The Company may experience increased operating expenses as a result of the required contributions to multiemployer pension plans, which may have a material adverse effect on the Company's results of operations, financial position or cash flows.

In addition, pursuant to ERISA, as amended by MPPAA, the Company could incur a partial or complete withdrawal liability upon withdrawing from a plan, exiting a market in which it does business with a union workforce or upon termination of a plan to the extent these plans are underfunded.

The Company's operations may be negatively impacted by cyber attacks or acts of terrorism.

The Company operates in industries that require continual operation of sophisticated information technology systems and network infrastructure. While the Company has developed procedures and processes that are designed to protect these systems, they may be vulnerable to failures or unauthorized access due to hacking, viruses, acts of terrorism or other causes. If the technology systems were to fail or be breached and these systems were not recovered in a timely manner, the Company's operational systems and infrastructure, such as the Company's electric generation, transmission and distribution facilities and its oil and natural gas production, storage and pipeline systems, may be unable to fulfill critical business functions. Any such disruption could result in a decrease in the Company's revenues and/or significant remediation costs which could have a material adverse effect on the Company's results of operations, financial position and cash flows. Additionally, because generation, transmission systems and gas pipelines are part of an interconnected system, a disruption elsewhere in the system could negatively impact the Company's business.

The Company's business requires access to sensitive customer data in the ordinary course of business. Despite the Company's implementation of security measures, a failure or breach of a security system could compromise sensitive and confidential information and data. Such an event could result in negative publicity, remediation costs and possible legal claims and fines which could adversely affect the Company's financial results. The Company's third party service providers that perform critical business functions or have access to sensitive and confidential information and data may also be vulnerable to security breaches and other risks that could have an adverse effect on the Company.

Other factors that could impact the Company's businesses.

The following are other factors that should be considered for a better understanding of the financial condition of the Company. These other factors may impact the Company's financial results in future periods.

- Acquisition, disposal and impairments of assets or facilities
- Changes in operation, performance and construction of plant facilities or other assets
- Changes in present or prospective generation
- The ability to obtain adequate and timely cost recovery for the Company's regulated operations through regulatory proceedings
- The availability of economic expansion or development opportunities
- Population growth rates and demographic patterns
- Market demand for, available supplies of, and/or costs of, energy- and construction-related products and services
- The cyclical nature of large construction projects at certain operations
- Changes in tax rates or policies
- Unanticipated project delays or changes in project costs, including related energy costs
- Unanticipated changes in operating expenses or capital expenditures
- Labor negotiations or disputes
- Inability of the various contract counterparties to meet their contractual obligations
- Changes in accounting principles and/or the application of such principles to the Company
- Changes in technology
- Changes in legal or regulatory proceedings
- The ability to effectively integrate the operations and the internal controls of acquired companies
- The ability to attract and retain skilled labor and key personnel
- Increases in employee and retiree benefit costs and funding requirements

Item 1B. Unresolved Staff Comments

The Company has no unresolved comments with the SEC.

Item 3. Legal Proceedings

For information regarding legal proceedings, see Item 8 – Note 19, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

For information regarding mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and Item 104 of Regulation S-K, see Exhibit 95 to this Form 10-K, which is incorporated herein by reference.

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

The Company's common stock is listed on the New York Stock Exchange under the symbol "MDU." The price range of the Company's common stock as reported by The Wall Street Journal composite tape during 2012 and 2011 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Declared Per Share
2012			
First quarter	**$22.50**	**$21.14**	**$.1675**
Second quarter	**23.21**	**20.76**	**.1675**
Third quarter	**23.11**	**21.42**	**.1675**
Fourth quarter	**22.23**	**19.59**	**.1725**
			$.6750
2011			
First quarter	$23.00	$20.11	$.1625
Second quarter	24.05	21.47	.1625
Third quarter	23.28	18.25	.1625
Fourth quarter	22.19	18.00	.1675
			$.6550

As of December 31, 2012, the Company's common stock was held by approximately 14,400 stockholders of record.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. For more information on factors that may limit the Company's ability to pay dividends see Item 8 – Note 12.

The following table includes information with respect to the Company's purchase of equity securities:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased (1)	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (2)
October 1 through October 31, 2012	–			
November 1 through November 30, 2012	49,203	$20.12		
December 1 through December 31, 2012	4,685	20.80		
Total	53,888			

(1) Represents shares of common stock purchased on the open market in connection with annual stock grants made to the Company's non-employee directors and for those directors who elected to receive additional shares of common stock in lieu of a portion of their cash retainer.

(2) Not applicable. The Company does not currently have in place any publicly announced plans or programs to purchase equity securities.

Item 6. Selected Financial Data

	2012 (a)	2011	2010	2009 (b)	2008 (c)	2007
Selected Financial Data						
Operating revenues (000's):						
Electric	**$ 236,895**	$ 225,468	$ 211,544	$ 196,171	$ 208,326	$ 193,367
Natural gas distribution	**754,848**	907,400	892,708	1,072,776	1,036,109	532,997
Pipeline and energy services	**193,157**	278,343	329,809	307,827	532,153	447,063
Exploration and production	**448,617**	453,586	434,354	439,655	712,279	514,854
Construction materials and contracting	**1,617,425**	1,510,010	1,445,148	1,515,122	1,640,683	1,761,473
Construction services	**938,558**	854,389	789,100	819,064	1,257,319	1,103,215
Other	**10,370**	11,446	7,727	9,487	10,501	10,061
Intersegment eliminations	**(124,439)**	(190,150)	(200,695)	(183,601)	(394,092)	(315,134)
	$4,075,431	$4,050,492	$3,909,695	$4,176,501	$5,003,278	$4,247,896
Operating income (loss) (000's):						
Electric	**$ 49,852**	$ 49,096	$ 48,296	$ 36,709	$ 35,415	$ 31,652
Natural gas distribution	**67,579**	82,856	75,697	76,899	76,887	32,903
Pipeline and energy services	**49,139**	45,365	46,310	69,388	49,560	58,026
Exploration and production	**(276,642)**	133,790	143,169	(473,399)	202,954	227,728
Construction materials and contracting	**57,864**	51,092	63,045	93,270	62,849	138,635
Construction services	**66,531**	39,144	33,352	44,255	81,485	75,511
Other	**4,884**	5,024	858	(219)	2,887	(7,335)
	$ 19,207	$ 406,367	$ 410,727	$ (153,097)	$ 512,037	$ 557,120
Earnings (loss) on common stock (000's):						
Electric	**$ 30,634**	$ 29,258	$ 28,908	$ 24,099	$ 18,755	$ 17,700
Natural gas distribution	**29,409**	38,398	36,944	30,796	34,774	14,044
Pipeline and energy services	**26,588**	23,082	23,208	37,845	26,367	31,408
Exploration and production	**(177,283)**	80,282	85,638	(296,730)	122,326	142,485
Construction materials and contracting	**32,420**	26,430	29,609	47,085	30,172	77,001
Construction services	**38,429**	21,627	17,982	25,589	49,782	43,843
Other	**4,797**	6,190	21,046	7,357	10,812	(4,380)
Earnings (loss) on common stock before income (loss) from discontinued operations	**(15,006)**	225,267	243,335	(123,959)	292,988	322,101
Income (loss) from discontinued operations, net of tax	**13,567**	(12,926)	(3,361)	–	–	109,334
	$ (1,439)	$ 212,341	$ 239,974	$ (123,959)	$ 292,988	$ 431,435
Earnings (loss) per common share before discontinued operations – diluted	**$ (.08)**	$ 1.19	$ 1.29	$ (.67)	$ 1.59	$ 1.76
Discontinued operations, net of tax	**.07**	(.07)	(.02)	–	–	.60
	$ (.01)	$ 1.12	$ 1.27	$ (.67)	$ 1.59	$ 2.36
Common Stock Statistics						
Weighted average common shares outstanding – diluted (000's)	**188,826**	188,905	188,229	185,175	183,807	182,902
Dividends declared per common share	**$ .6750**	$ .6550	$ .6350	$ .6225	$ .6000	$ .5600
Book value per common share	**$ 13.95**	$ 14.62	$ 14.22	$ 13.61	$ 14.95	$ 13.80
Market price per common share (year end)	**$ 21.24**	$ 21.46	$ 20.27	$ 23.60	$ 21.58	$ 27.61
Market price ratios:						
Dividend payout	**(d)**	58%	50%	(d)	38%	24%
Yield	**3.2%**	3.1%	3.2%	2.7%	2.9%	2.1%
Price/earnings ratio	**(d)**	19.2x	16.0x	(d)	13.6x	11.7x
Market value as a percent of book value	**152.3%**	146.8%	142.5%	173.4%	144.3%	200.1%
Profitability Indicators						
Return on average common equity	**(.1)%**	7.8%	9.1%	(4.9)%	11.0%	18.5%
Return on average invested capital	**1.1%**	6.3%	7.0%	(1.7)%	8.0%	13.1%
Fixed charges coverage, including preferred dividends	**– (e)**	4.0x	4.1x	– (f)	5.3x	6.4x

(a) Reflects $246.8 million of after-tax noncash write-downs of oil and natural gas properties.

(b) Reflects a $384.4 million after-tax noncash write-down of oil and natural gas properties.

(c) Reflects an $84.2 million after-tax noncash write-down of oil and natural gas properties.

(d) Not meaningful due to effects of the after-tax noncash write-down(s), as previously discussed.

(e) For more information on fixed charges coverage, including preferred dividends, see Item 7 – MD&A.

(f) Due to the $384.4 million after-tax noncash write-down of oil and natural gas properties, earnings were insufficient by $228.7 million to cover fixed charges. If the $384.4 million after-tax noncash write-down is excluded, the coverage of fixed charges, including preferred dividends would have been 4.6 times. The coverage of fixed charges including preferred stock dividends, that excludes the effect of the after-tax noncash write-down of oil and natural gas properties is a non-GAAP financial measure. The Company believes that this non-GAAP financial measure is useful because the write-down excluded is not indicative of the Company's cash flows available to meet its fixed charges obligations. The presentation of this additional information is not meant to be considered a substitute for financial measures prepared in accordance with GAAP.

Note: Cascade and Intermountain, natural gas distribution businesses, were acquired on July 2, 2007, and October 1, 2008, respectively.

Item 6. Selected Financial Data (continued)

	2012	2011	2010	2009	2008	2007
General						
Total assets (000's)	**$6,682,491**	$6,556,125	$6,303,549	$5,990,952	$6,587,845	$5,592,434
Total long-term debt (000's)	**$1,744,975**	$1,424,678	$1,506,752	$1,499,306	$1,647,302	$1,308,463
Capitalization ratios:						
Common equity	**60%**	66%	64%	63%	61%	66%
Total debt	**40**	34	36	37	39	34
	100%	100%	100%	100%	100%	100%
Electric						
Retail sales (thousand kWh)	**2,996,528**	2,878,852	2,785,710	2,663,560	2,663,452	2,601,649
Sales for resale (thousand kWh)	**14,094**	63,899	58,321	90,789	223,778	165,639
Electric system summer and firm purchase contract PRCs (Interconnected system)	**552.8**	572.8	553.3	(a)	(a)	(a)
Electric system peak demand obligation, including firm purchase contracts, PRCs (Interconnected system)	**550.7**	524.2	529.5	(a)	(a)	(a)
Demand peak – kW (Interconnected system)	**573,587**	535,761	525,643	525,643	525,643	525,643
Electricity produced (thousand kWh)	**2,299,686**	2,488,337	2,472,288	2,203,665	2,538,439	2,253,851
Electricity purchased (thousand kWh)	**870,516**	645,567	521,156	682,152	516,654	576,613
Average cost of fuel and purchased power per kWh	**$ .023**	$ .021	$ .021	$ .023	$ .025	$ .025
Natural Gas Distribution (b)						
Sales (Mdk)	**93,810**	103,237	95,480	102,670	87,924	52,977
Transportation (Mdk)	**132,010**	124,227	135,823	132,689	103,504	54,698
Degree days (% of normal)						
Montana-Dakota/Great Plains	**84%**	101%	98%	104%	103%	93%
Cascade	**96%**	103%	96%	105%	108%	102%
Intermountain	**91%**	107%	100%	107%	90%	–
Pipeline and Energy Services						
Transportation (Mdk)	**137,720**	113,217	140,528	163,283	138,003	140,762
Gathering (Mdk)	**47,084**	66,500	77,154	92,598	102,064	92,414
Customer natural gas storage balance (Mdk)	**43,731**	36,021	58,784	61,506	30,598	50,219
Exploration and Production						
Production:						
Oil (MBbls)	**3,694**	2,724	2,767	2,557	2,232	1,857
NGL (MBbls)	**828**	776	495	554	576	508
Natural gas (MMcf)	**33,214**	45,598	50,391	56,632	65,457	62,798
Total production (MBOE)	**10,058**	11,099	11,661	12,550	13,717	12,831
Average realized prices (including hedges):						
Oil (per Bbl)	**$ 86.52**	$ 86.66	$ 69.59	$ 50.67	$ 88.66	$ 62.94
NGL (per Bbl)	**$ 39.81**	$ 54.06	$ 44.93	$ 32.18	$ 54.65	$ 45.78
Natural gas (per Mcf)	**$ 2.89**	$ 3.85	$ 4.36	$ 5.16	$ 7.38	$ 5.96
Average realized prices (excluding hedges):						
Oil (per Bbl)	**$ 84.84**	$ 91.62	$ 70.61	$ 53.57	$ 89.41	$ 63.29
NGL (per Bbl)	**$ 39.81**	$ 54.06	$ 44.93	$ 32.18	$ 54.65	$ 45.78
Natural gas (per Mcf)	**$ 2.08**	$ 3.30	$ 3.57	$ 2.99	$ 7.29	$ 5.37
Proved reserves:						
Oil (MBbls)	**33,453**	27,005	25,666	25,930	25,238	24,270
NGL (MBbls)	**7,153**	7,342	7,201	8,286	9,110	6,342
Natural gas (MMcf)	**239,278**	379,827	448,397	448,425	604,282	523,737
Total proved reserves (MBOE)	**80,486**	97,651	107,599	108,954	135,062	117,901
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	**23,285**	24,736	23,349	23,995	31,107	36,912
Asphalt (tons)	**5,988**	6,709	6,279	6,360	5,846	7,062
Ready-mixed concrete (cubic yards)	**3,157**	2,864	2,764	3,042	3,729	4,085
Aggregate reserves (000's tons)	**1,088,236**	1,088,833	1,107,396	1,125,491	1,145,161	1,215,253

(a) Information not available for periods prior to 2010.
(b) Cascade and Intermountain were acquired on July 2, 2007, and October 1, 2008, respectively.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview

The Company's strategy is to apply its expertise in energy and transportation infrastructure industries to increase market share, increase profitability and enhance shareholder value through:

- Organic growth as well as a continued disciplined approach to the acquisition of well-managed companies and properties
- The elimination of system-wide cost redundancies through increased focus on integration of operations and standardization and consolidation of various support services and functions across companies within the organization
- The development of projects that are accretive to earnings per share and return on invested capital

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities, revolving credit facilities and the issuance from time to time of debt and equity securities. For more information on the Company's net capital expenditures, see Liquidity and Capital Commitments.

The key strategies for each of the Company's business segments and certain related business challenges are summarized below. For a summary of the Company's business segments, see Item 8 – Note 15.

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide competitively priced energy and related services to customers. The electric and natural gas distribution segments continually seek opportunities to retain, grow and expand their customer base through extensions of existing operations, including building and upgrading electric generation and transmission and natural gas systems, and through selected acquisitions of companies and properties at prices that will provide stable cash flows and an opportunity for the Company to earn a competitive return on investment.

Challenges Both segments are subject to extensive regulation in the state jurisdictions where they conduct operations with respect to costs and permitted returns on investment as well as subject to certain operational, system integrity and environmental regulations. These regulations can require substantial investment to upgrade facilities. The ability of these segments to grow through acquisitions is subject to significant competition. In addition, the ability of both segments to grow service territory and customer base is affected by the economic environment of the markets served and competition from other energy providers and fuels. The construction of any new electric generating facilities, transmission lines and other service facilities are subject to increasing cost and lead time, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which will necessitate increases in electric energy prices. Legislative and regulatory initiatives to increase renewable energy resources and reduce GHG emissions could impact the price and demand for electricity and natural gas.

Pipeline and Energy Services

Strategy Utilize the segment's existing expertise in energy infrastructure and related services to increase market share and profitability through optimization of existing operations, internal growth, and acquisitions of energy-related assets and companies. Incremental and new growth opportunities include: access to new energy sources for storage, gathering and transportation services; expansion of existing gathering, transmission and storage facilities; incremental expansion of pipeline capacity; expansion of midstream business to include liquid pipelines and processing activities; and expansion of related energy services.

Challenges Challenges for this segment include: energy price volatility; natural gas basis differentials; environmental and regulatory requirements; recruitment and retention of a skilled workforce; and competition from other pipeline and energy services companies.

Exploration and Production

Strategy Apply technology and utilize existing exploration and production expertise, with a focus on operated properties, to increase production and reserves from existing leaseholds, and to seek additional reserves and production opportunities both in new and existing areas to further expand the segment's asset base. By optimizing existing operations and taking advantage of new and incremental growth opportunities, this segment is focused on balancing the oil and natural gas commodity mix to maximize profitability with its goal to add value by increasing both reserves and production over the long term so as to generate competitive returns on investment.

Challenges Volatility in natural gas and oil prices; timely receipt of necessary permits and approvals; environmental and regulatory requirements; recruitment and retention of a skilled workforce; availability of drilling rigs, materials, auxiliary equipment and industry-related field services; inflationary pressure on development and operating costs; and competition from other exploration and production companies are ongoing challenges for this segment.

Construction Materials and Contracting

Strategy Focus on high-growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; strengthen long-term, strategic aggregate reserve position through purchase and/or lease opportunities; enhance profitability through cost containment, margin discipline and vertical integration of the segment's operations; and continue growth through organic and acquisition opportunities. Ongoing efforts to increase margin are being pursued through the implementation of a variety of continuous improvement programs, including corporate purchasing of equipment, parts and commodities (liquid asphalt, diesel fuel, cement and other materials), and negotiation of contract price escalation provisions. Vertical integration allows the segment to manage operations from aggregate mining to final lay-down of concrete and asphalt, with control of and access to permitted aggregate reserves being significant. A key element of the Company's long-term strategy for this business is to further expand its market presence in the higher-margin materials business (rock, sand, gravel, liquid asphalt, asphalt concrete, ready-mixed concrete and related products), complementing and expanding on the Company's expertise.

Challenges Volatility in the cost of raw materials such as diesel, gasoline, liquid asphalt, cement and steel, continue to be a concern. This business unit expects to continue cost containment efforts, positioning its operations for the resurgence in the private market, while continuing the emphasis on industrial, energy and public works projects.

Construction Services

Strategy Provide a competitive return on investment while operating in a competitive industry by: building new and strengthening existing customer relationships; effectively controlling costs; retaining, developing and recruiting talented employees; focusing our efforts on projects that will permit higher margins while properly managing risk.

Challenges This segment operates in highly competitive markets with many jobs subject to competitive bidding. Maintenance of effective operational and cost controls, retention of key personnel, managing through downturns in the economy and effective management of working capital are ongoing challenges.

For more information on the risks and challenges the Company faces as it pursues its growth strategies and other factors that should be considered for a better understanding of the Company's financial condition, see Item 1A – Risk Factors. For more information on each segment's key growth strategies, projections and certain assumptions, see Prospective Information.

For information pertinent to various commitments and contingencies, see Item 8 – Notes to Consolidated Financial Statements.

Earnings Overview

The following table summarizes the contribution to consolidated earnings (loss) by each of the Company's businesses.

Years ended December 31,	**2012**	2011	2010
	(Dollars in millions, where applicable)		
Electric	**$ 30.6**	$ 29.2	$ 28.9
Natural gas distribution	**29.4**	38.4	37.0
Pipeline and energy services	**26.6**	23.1	23.2
Exploration and production	**(177.2)**	80.3	85.6
Construction materials and contracting	**32.4**	26.4	29.6
Construction services	**38.4**	21.6	18.0
Other	**4.8**	6.2	21.0
Earnings (loss) before discontinued operations	**(15.0)**	225.2	243.3
Income (loss) from discontinued operations, net of tax	**13.6**	(12.9)	(3.3)
Earnings (loss) on common stock	**$ (1.4)**	$212.3	$240.0
Earnings (loss) per common share – basic:			
Earnings (loss) before discontinued operations	**$ (.08)**	$ 1.19	$ 1.29
Discontinued operations, net of tax	**.07**	(.07)	(.01)
Earnings (loss) per common share – basic	**$ (.01)**	$ 1.12	$ 1.28
Earnings (loss) per common share – diluted:			
Earnings (loss) before discontinued operations	**$ (.08)**	$ 1.19	$ 1.29
Discontinued operations, net of tax	**.07**	(.07)	(.02)
Earnings (loss) per common share – diluted	**$ (.01)**	$ 1.12	$ 1.27
Return on average common equity	**(.1)%**	7.8%	9.1%

2012 compared to 2011 Consolidated earnings for 2012 decreased $213.7 million from the prior year. This decrease was due to:

- Noncash write-downs of oil and natural gas properties of $246.8 million (after tax), lower average realized natural gas prices, decreased natural gas production, as well as higher depreciation, depletion and amortization expense, partially offset by increased oil production at the exploration and production business
- Decreased retail sales volumes at the natural gas distribution business, largely resulting from warmer weather than last year

Partially offsetting these decreases were:

- Income from discontinued operations of $13.6 million (after tax), largely related to a benefit from an arbitration charge reversal resulting from a favorable court ruling, as discussed in Item 8 – Note 3
- Higher workloads and margins in the Central and Western regions, higher equipment sales and rental margins, as well as higher margins in the Mountain region, partially offset by higher general and administrative expense at the construction services business
- Higher ready-mixed concrete and other product line margins and volumes, increased construction margins, as well as higher liquid asphalt oil margins and volumes, partially offset by lower gains from the sale of property, plant and equipment and lower aggregate and asphalt margins and volumes at the construction materials and contracting business
- Lower operation and maintenance expense from existing operations largely related to a $15.0 million (after tax) net benefit related to the natural gas gathering operations litigation, as discussed in Item 8 – Note 19, partially offset by lower natural gas gathering volumes from existing operations at the pipeline and energy services business

2011 compared to 2010 Consolidated earnings for 2011 decreased $27.7 million from the prior year. This decrease was due to:

- Absence of a $13.8 million (after tax) gain on the sale of the Brazilian Transmission Lines, as discussed in Item 8 – Note 4, as well as an increased loss of $9.6 million (after tax) from discontinued operations, as discussed in Item 8 – Note 3. Both of these items are included in the Other category.
- Lower average realized natural gas prices, decreased natural gas production, higher depreciation, depletion and amortization expense, increased lease operating costs, higher production and property taxes and higher general and administrative expense, partially offset by higher average realized oil prices and increased oil production at the exploration and production business

Partially offsetting these decreases were higher workloads and margins in the Western region, as well as higher equipment sales and rental margins, partially offset by lower workloads and margins in the Mountain region at the construction services business.

The pipeline and energy services business experienced lower storage services revenue and decreased transportation and gathering volumes, as well as lower operation and maintenance expense, primarily related to the absence of a natural gas gathering arbitration charge of $16.5 million (after tax).

Financial and Operating Data

Below are key financial and operating data for each of the Company's businesses.

Electric

Years ended December 31,	**2012**	2011	2010
	(Dollars in millions, where applicable)		
Operating revenues	**$236.9**	$225.5	$211.6
Operating expenses:			
Fuel and purchased power	**72.4**	64.5	63.1
Operation and maintenance	**71.8**	70.3	63.8
Depreciation, depletion and amortization	**32.5**	32.2	27.3
Taxes, other than income	**10.3**	9.4	9.1
	187.0	176.4	163.3
Operating income	**49.9**	49.1	48.3
Earnings	**$ 30.6**	$ 29.2	$ 28.9
Retail sales (million kWh)	**2,996.5**	2,878.9	2,785.7
Sales for resale (million kWh)	**14.1**	63.9	58.3
Average cost of fuel and purchased power per kWh	**$ .023**	$ .021	$ .021

2012 compared to 2011 Electric earnings increased $1.4 million (5 percent) compared to the prior year due to:

- Higher retail sales volumes of 4 percent, primarily to small commercial and industrial and residential customers, reflecting increased demand due to warmer summer weather than last year, as well as increased customer growth, offset in part by decreased volumes to large commercial and industrial customers
- Higher other income of $900,000 (after tax), largely higher allowance for funds used during construction
- Lower net interest expense of $900,000 (after tax), including higher capitalized interest

Partially offsetting these increases were:

- Higher income taxes of $1.4 million, including the absence of an income tax benefit related to favorable resolution of certain income tax matters in 2011
- Increased taxes other than income of $600,000 (after tax), primarily related to higher property taxes
- Higher operation and maintenance expense of $500,000 (after tax), largely related to increased contract services at certain of the Company's electric generation stations, as well as higher payroll-related costs, partially offset by lower benefit-related costs

2011 compared to 2010 Electric earnings increased $300,000 (1 percent) compared to the prior year due to:

- Higher electric retail sales margins, primarily due to higher rates in North Dakota, Montana and Wyoming
- Increased retail sales volumes of 3 percent, primarily to residential and small commercial and industrial customers, reflecting increased customers and demand
- Lower income taxes of $3.4 million, including an income tax benefit of $1.2 million related to favorable resolution of certain income tax matters, higher production tax credits, as well as a reduction of income taxes associated with benefits

Partially offsetting these increases were:

- Higher operation and maintenance expense of $4.1 million (after tax), primarily increased benefit-related costs, as well as increased contract services
- Increased depreciation, depletion and amortization expense of $3.0 million (after tax), including the effects of higher property, plant and equipment balances
- Lower other income of $2.2 million (after tax), largely lower allowance for funds used during construction related to electric generation projects, which were placed in service in 2010
- Higher net interest expense of $1.4 million (after tax), including lower capitalized interest

Natural Gas Distribution

Years ended December 31,	**2012**	2011	2010
	(Dollars in millions, where applicable)		
Operating revenues	**$754.8**	$907.4	$892.7
Operating expenses:			
Purchased natural gas sold	**457.4**	594.6	589.3
Operation and maintenance	**139.4**	137.3	137.4
Depreciation, depletion and amortization	**45.7**	44.6	43.0
Taxes, other than income	**44.7**	48.0	47.3
	687.2	824.5	817.0
Operating income	**67.6**	82.9	75.7
Earnings	**$ 29.4**	$ 38.4	$ 37.0
Volumes (MMdk):			
Sales	**93.8**	103.3	95.5
Transportation	**132.0**	124.2	135.8
Total throughput	**225.8**	227.5	231.3
Degree days (% of normal)*			
Montana-Dakota/Great Plains	**84%**	101%	98%
Cascade	**96%**	103%	96%
Intermountain	**91%**	107%	100%
Average cost of natural gas, including transportation, per dk	**$ 4.88**	$ 5.76	$ 6.17

* Degree days are a measure of the daily temperature-related demand for energy for heating.

2012 compared to 2011 The natural gas distribution business experienced a decrease in earnings of $9.0 million (23 percent) compared to the prior year due to:

- Lower earnings of $7.6 million (after tax) related to decreased retail sales volumes, largely resulting from warmer weather than last year, partially offset by weather normalization in certain jurisdictions
- Higher taxes other than income of $1.3 million (after tax), primarily related to higher property taxes. This increase was more than offset by lower taxes other than income resulting from lower natural gas revenues.
- Higher income taxes of $1.2 million, primarily related to the absence of a reduction of deferred income taxes associated with benefits in 2011
- Increased operation and maintenance expense of $700,000 (after tax), including increased contract services

These decreases were partially offset by higher other income of $1.1 million (after tax), primarily related to allowance for funds used during construction.

2011 compared to 2010 The natural gas distribution business experienced an increase in earnings of $1.4 million (4 percent) compared to the prior year due to increased retail sales volumes and margins, largely resulting from colder weather than the prior year.

Partially offsetting this increase were:

- Higher regulated operation and maintenance expense of $3.5 million (after tax), primarily higher benefit-related costs
- Higher income taxes of $2.1 million, primarily related to the absence of a 2010 income tax benefit of $4.8 million related to a reduction in deferred income taxes associated with property, plant and equipment, partially offset by a reduction of income taxes associated with benefits
- Lower nonregulated energy-related services of $1.3 million (after tax), largely related to lower pipeline project activity
- Increased depreciation, depletion and amortization expense of $1.0 million (after tax), primarily resulting from higher property, plant and equipment balances

The previous table also reflects lower revenue and lower operation and maintenance expense related to pipeline project activity.

Pipeline and Energy Services

Years ended December 31,	**2012**	2011	2010
		(Dollars in millions)	
Operating revenues	**$193.1**	$278.3	$329.8
Operating expenses:			
Purchased natural gas sold	**50.5**	125.3	153.9
Operation and maintenance	**52.2***	68.9	90.6**
Depreciation, depletion and amortization	**27.7**	25.5	26.0
Taxes, other than income	**13.6**	13.2	13.0
	144.0	232.9	283.5
Operating income	**49.1**	45.4	46.3
Earnings	**$ 26.6***	$ 23.1	$ 23.2**
Transportation volumes (MMdk)	**137.7**	113.2	140.5
Natural gas gathering volumes (MMdk)	**47.1**	66.5	77.2
Customer natural gas storage balance (MMdk):			
Beginning of period	**36.0**	58.8	61.5
Net injection (withdrawal)	**7.7**	(22.8)	(2.7)
End of period	**43.7**	36.0	58.8

* Results reflect a net benefit of $24.1 million ($15.0 million after tax) related to the natural gas gathering operations litigation, largely reflected in operation and maintenance expense, as discussed in Item 8 – Note 19.

** Reflects a natural gas gathering arbitration charge of $26.6 million ($16.5 million after tax), as discussed in Item 8 – Note 19.

2012 compared to 2011 Pipeline and energy services earnings increased $3.5 million (15 percent) largely due to:

- Lower operation and maintenance expense from existing operations largely related to a $15.0 million (after tax) net benefit related to the natural gas gathering operations litigation, as discussed in Item 8 – Note 19, which was partially offset by an impairment of certain natural gas gathering assets of $1.7 million (after tax) due largely to low natural gas prices
- Higher oil and natural gas gathering and processing volumes from a recent acquisition, as discussed in Item 8 – Note 2

Partially offsetting the earnings increase were:

- Lower earnings of $10.4 million (after tax) due to lower natural gas gathering volumes from existing operations, largely resulting from customers experiencing normal declines, production curtailments, deferral of certain natural gas development activity and the Company's divestments
- Lower storage services revenue of $600,000 (after tax), largely lower average storage balances, as well as lower withdrawal volumes

Results also reflect lower operating revenues and lower purchased natural gas sold, both related to lower natural gas prices and lower natural gas volumes.

2011 compared to 2010 Pipeline and energy services earnings decreased $100,000 largely due to:

- Lower storage services revenue of $7.1 million (after tax), largely lower storage balances
- Decreased transportation volumes of $4.6 million (after tax), largely lower volumes transported to storage resulting from decreased customer demand, as well as lower off-system transportation volumes
- Lower gathering volumes of $3.9 million (after tax), largely resulting from customers experiencing normal production declines

Partially offsetting the earnings decrease was lower operation and maintenance expense, primarily related to the absence of the natural gas gathering arbitration charge of $26.6 million ($16.5 million after tax) in 2010, as discussed in Item 8 – Note 19, partially offset by the absence of an insurance recovery that lowered costs in 2010 related to natural gas storage litigation. The natural gas storage litigation was settled in July 2009.

Exploration and Production

Years ended December 31,	**2012**	2011	2010
	(Dollars in millions, where applicable)		
Operating revenues:			
Oil	**$ 319.6**	$236.1	$192.5
NGL	**33.0**	41.9	22.3
Natural gas	**96.0**	175.6	219.6
	448.6	453.6	434.4
Operating expenses:			
Operation and maintenance:			
Lease operating costs	**77.7**	75.6	68.5
Gathering and transportation	**17.4**	24.3	23.5
Other	**37.0**	36.5	32.5
Depreciation, depletion and amortization	**160.7**	142.6	130.5
Taxes, other than income:			
Production and property taxes	**39.7**	40.8	35.5
Other	**1.0**	–	.7
Write-downs of oil and natural gas properties	**391.8**	–	–
	725.3	319.8	291.2
Operating income (loss)	**(276.7)**	133.8	143.2
Earnings (loss)	**$(177.2)**	$ 80.3	$ 85.6
Production:			
Oil (MBbls)	**3,694**	2,724	2,767
NGL (MBbls)	**828**	776	495
Natural gas (MMcf)	**33,214**	45,598	50,391
Total production (MBOE)	**10,058**	11,099	11,661
Average realized prices (including hedges):			
Oil (per Bbl)	**$ 86.52**	$86.66	$69.59
NGL (per Bbl)	**$ 39.81**	$54.06	$44.93
Natural gas (per Mcf)	**$ 2.89**	$ 3.85	$ 4.36
Average realized prices (excluding hedges):			
Oil (per Bbl)	**$ 84.84**	$91.62	$70.61
NGL (per Bbl)	**$ 39.81**	$54.06	$44.93
Natural gas (per Mcf)	**$ 2.08**	$ 3.30	$ 3.57
Average depreciation, depletion and amortization rate, per BOE	**$ 15.28**	$12.25	$10.64
Production costs, including taxes, per BOE:			
Lease operating costs	**$ 7.73**	$ 6.81	$ 5.87
Gathering and transportation	**1.73**	2.19	2.01
Production and property taxes	**3.94**	3.67	3.04
	$ 13.40	$12.67	$10.92

2012 compared to 2011 Earnings at the exploration and production business decreased $257.5 million due to:

- Noncash write-downs of oil and natural gas properties of $246.8 million (after tax), as discussed in Item 8 – Note 1
- Lower average realized natural gas prices of 25 percent
- Decreased natural gas production of 27 percent, largely related to normal declines, production curtailments, deferral of certain natural gas development activity and divestment of existing properties
- Higher depreciation, depletion and amortization expense of $11.4 million (after tax), due to higher depletion rates, partially offset by lower volumes
- Lower average realized NGL prices of 26 percent

Partially offsetting these decreases were:

- Increased oil production of 36 percent, primarily related to drilling activity in the Bakken area, as well as the Paradox Basin
- Lower gathering and transportation expense of $4.3 million (after tax), largely due to lower gathering costs resulting from lower volumes and lower gathering rates in the coalbed area

2011 compared to 2010 Earnings at the exploration and production business decreased $5.3 million (6 percent) due to:

- Lower average realized natural gas prices of 12 percent
- Decreased natural gas production of 10 percent, largely related to normal production declines at certain properties, partially offset by increased production from the South Texas properties resulting from drilling activity, as well as production from the Green River Basin properties, which were acquired in April 2010
- Higher depreciation, depletion and amortization expense of $7.6 million (after tax), due to higher depletion rates, partially offset by lower volumes
- Increased lease operating expenses of $4.4 million (after tax) largely related to higher well maintenance costs, including higher workover costs at the Cedar Creek Anticline properties, in which the Company holds a net profits interest; costs from the Green River Basin properties, which were acquired in April 2010; as well as higher costs resulting from increased production in the Bakken area and at the South Texas properties
- Higher production and property taxes of $3.3 million (after tax), largely resulting from higher oil prices excluding hedges
- Higher general and administrative expense of $2.0 million (after tax), largely higher payroll-related costs

Partially offsetting these decreases were:

- Higher average realized oil prices of 21 percent
- Increased oil production of 7 percent, largely related to drilling activity at the South Texas properties, as well as in the Bakken area, partially offset by normal production declines at certain properties

Construction Materials and Contracting

Years ended December 31,	**2012**	2011	2010
		(Dollars in millions)	
Operating revenues	**$1,617.4**	$1,510.0	$1,445.1
Operating expenses:			
Operation and maintenance	**1,442.5**	1,337.4	1,260.4
Depreciation, depletion and amortization	**79.5**	85.5	88.3
Taxes, other than income	**37.5**	36.0	33.4
	1,559.5	1,458.9	1,382.1
Operating income	**57.9**	51.1	63.0
Earnings	**$ 32.4**	$ 26.4	$ 29.6
Sales (000's):			
Aggregates (tons)	**23,285**	24,736	23,349
Asphalt (tons)	**5,988**	6,709	6,279
Ready-mixed concrete (cubic yards)	**3,157**	2,864	2,764

2012 compared to 2011 Earnings at the construction materials and contracting business increased $6.0 million (23 percent) due to:

- Higher earnings of $6.4 million (after tax) resulting from higher ready-mixed concrete margins and volumes, primarily in the North Central and Northwest regions, as well as higher other product line volumes and margins
- Increased construction margins of $3.6 million (after tax), largely related to increased construction margins in the South and Intermountain regions
- Higher earnings of $3.6 million (after tax) resulting from higher liquid asphalt oil margins and volumes
- Lower selling, general and administrative costs of $2.8 million (after tax), largely due to lower benefit and payroll-related costs

Partially offsetting the increases were:

- Lower gains of $4.0 million (after tax) from the sale of property, plant and equipment
- Lower earnings of $3.6 million (after tax) resulting from lower aggregate margins primarily due to higher costs, as well as lower volumes
- Lower earnings of $2.9 million (after tax) resulting from lower asphalt margins primarily due to higher costs, as well as lower volumes

2011 compared to 2010 Earnings at the construction materials and contracting business decreased $3.2 million (11 percent) due to:

- Lower earnings of $5.8 million (after tax) resulting from lower liquid asphalt oil margins, largely due to higher asphalt oil costs
- Lower earnings of $3.3 million (after tax) resulting from lower other product line margins, largely due to lower revenues and higher costs
- Lower earnings of $2.3 million (after tax) resulting from lower ready-mixed concrete margins, primarily due to higher costs

Partially offsetting the decreases were:

- Increased construction margins of $5.4 million (after tax), largely due to increased margins and volumes in the Pacific, North Central and Mountain regions
- Lower interest expense of $2.3 million (after tax), primarily due to lower average interest rates

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Construction Services

Years ended December 31,	**2012**	2011	2010
		(In millions)	
Operating revenues	**$938.6**	$854.4	$789.1
Operating expenses:			
Operation and maintenance	**831.9**	778.5	719.7
Depreciation, depletion and amortization	**11.1**	11.4	12.1
Taxes, other than income	**29.1**	25.4	23.9
	872.1	815.3	755.7
Operating income	**66.5**	39.1	33.4
Earnings	**$ 38.4**	$ 21.6	$ 18.0

2012 compared to 2011 Construction services earnings increased $16.8 million (78 percent) compared to the prior year due to higher earnings of $21.3 million resulting from higher workloads and margins in the Central and Western regions, higher equipment sales and rental margins, as well as higher margins in the Mountain region. These increases were partially offset by higher general and administrative expense of $4.6 million (after tax), including higher payroll-related costs.

2011 compared to 2010 Construction services earnings increased $3.6 million (20 percent) compared to the prior year primarily due to higher workloads and margins in the Western region, higher equipment sales and rental margins, as well as decreased general and administrative expense of $1.1 million (after tax). The earnings increase was partially offset by lower workloads and margins in the Mountain region, as well as lower margins in the Central region.

Other and Intersegment Transactions

Amounts presented in the preceding tables will not agree with the Consolidated Statements of Income due to the Company's other operations and the elimination of intersegment transactions. The amounts relating to these items are as follows:

Years ended December 31,	**2012**	2011	2010
		(In millions)	
Other:			
Operating revenues	**$ 10.4**	$ 11.4	$ 7.7
Operation and maintenance	**3.3**	4.7	4.8
Depreciation, depletion and amortization	**2.0**	1.6	1.6
Taxes, other than income	**.2**	.1	.5
Intersegment transactions:			
Operating revenues	**$124.4**	$190.1	$200.7
Purchased natural gas sold	**82.7**	147.7	175.4
Operation and maintenance	**41.7**	42.4	25.3

For more information on intersegment eliminations, see Item 8 – Note 15.

Prospective Information

The following information highlights the key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters for certain of the Company's businesses. Many of these highlighted points are "forward-looking statements." There is no assurance that the Company's projections, including estimates for growth and changes in earnings, will in fact be achieved. Please refer to assumptions contained in this section, as well as the various important factors listed in Item 1A – Risk Factors. Changes in such assumptions and factors could cause actual future results to differ materially from the Company's growth and earnings projections.

MDU Resources Group, Inc.

- Earnings per common share for 2013, diluted, are projected in the range of $1.20 to $1.35. The Company expects the approximate percentage of 2013 earnings per common share by quarter to be:
  - First quarter – 15 percent
  - Second quarter – 20 percent
  - Third quarter – 35 percent
  - Fourth quarter – 30 percent
- The Company's long-term compound annual growth goals on earnings per share from operations are in the range of 7 to 10 percent.
- The Company continually seeks opportunities to expand through organic growth opportunities and strategic acquisitions.
- The Company focuses on creating value through vertical integration between its business units. For example, the pipeline and energy services business' planned partially owned diesel topping plant located in the Bakken region expects to have the construction materials and services business involved in constructing the facility, the exploration and production business supplying production to the plant, the pipeline transporting natural gas to the plant, and the utility supplying electricity.

Electric and natural gas distribution

- The Company filed an application with the SDPUC on December 21, 2012, for a natural gas rate increase, as discussed in Item 8 – Note 18.
- The Company filed an application with the MTPSC on September 26, 2012, for a natural gas rate increase, as discussed in Item 8 – Note 18.
- The EPA approved the South Dakota Regional Haze Program, which requires the Big Stone Station to install and operate a BART air-quality control system to reduce emissions of particulate matter, sulfur dioxide and nitrogen oxides. The Company's share of the cost for the installation is estimated at $125 million and is expected to be complete in 2015. The NDPSC has approved advance determination of prudence for recovery of costs related to this system in electric rates charged to customers.
- The Company plans to construct and operate an 88-MW simple-cycle natural gas turbine and associated facilities, with an estimated project cost of $86 million and a projected in-service date in late 2014. It will be located on owned property that is adjacent to the Company's Heskett Generating Station near Mandan, North Dakota. The capacity is necessary to meet the requirements of the Company's integrated electric system customers and will be a partial replacement for third-party contract capacity expiring in 2015. Advance determination of prudence and a Certificate of Public Convenience and Necessity have been received from the NDPSC.

- The Company plans to invest approximately $70 million in 2013 to serve the growing electric and natural gas customer base associated with the Bakken oil development in western North Dakota and eastern Montana.
- The Company expects to grow its rate base by approximately 6 percent compounded annually over the next five years.
- The Company is analyzing potential projects for accommodating load growth in its industrial and agricultural sectors, with company- and customer-owned pipeline facilities designed to serve existing facilities served by fuel oil or propane, and to serve new customers. The Company is currently engaged in a 30-mile natural gas line project into the Hanford Nuclear Site in Washington.
- Currently the Company is involved with a number of pipeline projects to enhance the reliability and deliverability of its system in the Pacific Northwest and Idaho.
- The Company is pursuing opportunities associated with the potential development of high-voltage transmission lines and system enhancements targeted toward delivery of energy to major market areas.

Pipeline and energy services

- The Company and Calumet Specialty Products Partners, L.P., have formed a joint venture to develop, build and operate a 20,000 BOPD diesel topping plant in southwestern North Dakota. The facility will process Bakken crude and market the diesel within the Bakken region. Land has been purchased near Dickinson, North Dakota, for the site, and permitting activities are under way. Total project costs are estimated to be approximately $280 million to $300 million, with a projected in-service date in late 2014.
- In May 2012, the Company purchased a 50 percent undivided interest in Whiting Oil and Gas Corporation's Pronghorn natural gas and oil midstream assets near Belfield, North Dakota, in the Bakken area. The Company invested approximately $100 million in 2012 including the purchase price. The Belfield natural gas processing plant has an inlet processing capacity of 35 MMcf per day. The Company will receive a full year of benefit from this acquisition in 2013.
- In August 2012, the Company placed in service approximately 13 miles of high-pressure transmission pipeline from the Stateline processing facilities in northwestern North Dakota to deliver natural gas into the Northern Border Pipeline, which is expected to result in increased transportation volumes for 2013.
- Dry natural gas gathering volumes are expected to be lower in 2013 compared to 2012 because of curtailments and the deferral of certain development activity.
- The Company recently reached an agreement to construct a pipeline in 2014 to connect the planned Garden Creek II gas processing plant in northwestern North Dakota to deliver natural gas into the Northern Border Pipeline.
- The Company continues to pursue expansion of facilities and services offered to customers. Energy development within its geographic region, which includes portions of Colorado, Montana, North Dakota and Wyoming, is expanding, most notably the Bakken area of North Dakota and eastern Montana. The Company owns an extensive natural gas pipeline system in the Bakken area. Ongoing energy development is expected to have many direct and indirect benefits to this business.

Exploration and production

- The Company expects to spend approximately $400 million in capital expenditures in 2013. With improving well cost efficiencies and having essentially completed the extensive 2012 exploration program, the capital program will focus on growth projects where the Company expects higher returns namely the Bakken, Paradox Basin and Texas, as described later. Follow-up on development activity of the 2012 exploration program (beyond the activity in the Paradox) could take place in late 2013 or early 2014 depending upon the economic competitiveness of those plays once they are fully appraised. The 2013 planned capital expenditure total does not include potential acquisitions.
- For 2013, the Company expects a 25 to 30 percent increase in oil production, a flat to slight increase in NGL production, and a 15 to 25 percent decrease in natural gas production. The majority of the capital program is focused on growing oil production considering current relative commodity prices. The Company expects to return to some natural gas development when the commodity prices make it more profitable to do so.
- The Company has a total of seven drilling rigs deployed on its acreage in the Bakken, Texas and Paradox areas.
- Bakken areas
  - The Company owns a total of approximately 127,000 net acres of leaseholds in Mountrail, Stark and Richland counties.
  - Production grew 71 percent in the fourth quarter of 2012 compared to last year.

- Capital expenditures are expected to total approximately $200 million in 2013. The Company is currently operating five rigs in the play; with improving drilling efficiencies and other factors that number could vary across 2013 from three to five rigs.
- Following are recent well results:

Well Name	Spacing	1st Production Date	24-Hour IP Rate (BOEPD)
Sundts 23-14-15H	1280	10/27/2012	1,494
Corpron 16-21-22H	1280	11/16/2012	1,395
Miriah 19-30-29H	1280	11/29/2012	972
Bauer 25-36H	1280	12/20/2012	1,290
Niemitalo 24-13H	1280	1/7/2013	1,071
State 34-33-28H	1280	1/9/2013	1,053
Fladeland 34-31H	640	1/13/2013	642

- Paradox Basin, Utah
  - The Company has increased its holding to approximately 83,000 net acres and also has an option to lease another 20,000 acres.
  - Production grew more than 1,400 percent in the fourth quarter of 2012 compared to last year.
  - The Company has experienced strong well results with the Paradox 12-1 consistently producing 1,500 BOPD since mid-September with consistently high-flowing pressures above 2,000 psi.
  - The Company is continuing to proceed systematically in this play, and anticipates spending $70 million of capital expenditures in 2013. As the play is fully understood, the opportunity to ramp up to full-scale development could increase the planned investment. At this point, the potential appears very significant.
  - Approximately 50 to 75 future net locations have been identified. Estimated gross ultimate recovery rates per well range from 250,000 to 1 million Bbls.
- Texas
  - The Company is targeting areas that have the potential for higher liquids content with approximately $40 million of capital planned for 2013.
- Other opportunities
  - The Company plans to drill one horizontal well during 2013 in Sioux County, Nebraska. Upon evaluation of this well, the Company may exercise an option to purchase a 65 percent working interest in approximately 79,000 gross acres.
  - The remaining forecasted 2013 capital has been allocated to other operated and non-operated opportunities.
- Earnings guidance reflects estimated average NYMEX index prices for February through December in the ranges of $85.00 to $95.00 per Bbl of crude oil, and $3.25 to $3.75 per Mcf of natural gas. Estimated prices for NGL are in the range of $30.00 to $45.00 per Bbl.
- For 2013 the Company has hedged 7,000 BOPD, with an additional 2,000 BOPD for the period March through December, utilizing swaps and costless collars with a weighted average price of $98.81 and $92.50/$107.03 (floor/ceiling) respectively. For 2013, the Company has hedged 30,000 MMBtu of natural gas per day, with an additional 10,000 MMBtu per day for February through December and an additional 10,000 MMBtu per day for March through December, utilizing swaps at a weighted average price of $3.74.

- The hedges that are in place as of February 15, 2013, are summarized in the following chart:

Commodity	Type	Index	Period Outstanding	Forward Notional Volume (Bbl/MMBtu)	Price (Per Bbl/MMBtu)
Crude Oil	Collar	NYMEX	1/13 – 12/13	365,000	$95.00-$117.00
Crude Oil	Collar	NYMEX	1/13 – 12/13	365,000	$90.00-$97.05
Crude Oil	Swap	NYMEX	1/13 – 12/13	182,500	$95.00
Crude Oil	Swap	NYMEX	1/13 – 12/13	182,500	$95.30
Crude Oil	Swap	NYMEX	1/13 – 12/13	182,500	$100.00
Crude Oil	Swap	NYMEX	1/13 – 12/13	182,500	$100.02
Crude Oil	Swap	NYMEX	1/13 – 12/13	365,000	$102.00
Crude Oil	Swap	NYMEX	1/13 – 12/13	365,000	$104.00
Crude Oil	Swap	NYMEX	1/13 – 12/13	365,000	$98.00
Crude Oil	Swap	NYMEX	3/13 – 12/13	153,000	$94.15
Crude Oil	Swap	NYMEX	3/13 – 12/13	153,000	$94.00
Crude Oil	Swap	NYMEX	3/13 – 12/13	306,000	$97.45
Crude Oil	Swap	NYMEX	1/14 – 6/14	181,000	$95.15
Crude Oil	Swap	NYMEX	1/14 – 6/14	181,000	$95.00
Natural Gas	Swap	NYMEX	1/13 – 12/13	3,650,000	$3.76
Natural Gas	Swap	NYMEX	1/13 – 12/13	3,650,000	$3.90
Natural Gas	Swap	NYMEX	1/13 – 12/13	3,650,000	$4.00
Natural Gas	Swap	NYMEX	2/13 – 12/13	3,340,000	$3.50
Natural Gas	Swap	NYMEX	3/13 – 12/13	3,060,000	$3.50
Natural Gas	Swap	NYMEX	1/14 – 12/14	3,650,000	$4.13

Construction materials and contracting

- Work backlog as of December 31, 2012, was approximately $406 million, compared to approximately $384 million a year ago. Private work represents 14 percent of the backlog, up from 8 percent in 2011. Public work represents 86 percent of the backlog. The backlog includes a variety of projects such as highway paving projects, airports, bridge work, reclamation and harbor expansions.
- The Company's backlog in the Bakken area of North Dakota is approximately $32 million.
- Projected revenues included in the Company's 2013 earnings guidance are in the range of $1.5 billion to $1.7 billion.
- The Company anticipates margins in 2013 to be higher compared to 2012.
- The Company continues to pursue opportunities for expansion in energy projects such as refineries, transmission, wind towers and geothermal. Initiatives are aimed at capturing additional market share and expanding into new markets.
- As the country's fifth-largest sand and gravel producer, the Company will continue to strategically manage its 1.1 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.

Construction services

- Work backlog as of December 31, 2012, was approximately $325 million, compared to approximately $308 million a year ago. The backlog includes a variety of projects such as substation and line construction, solar and other commercial, institutional and industrial projects including refinery work.
- The Company's backlog in the Bakken area of North Dakota is approximately $1 million.
- Projected revenues included in the Company's 2013 earnings guidance are in the range $850 million to $950 million.
- The Company anticipates margins in 2013 to be lower compared to 2012.
- The Company continues to pursue opportunities for expansion in energy projects such as refineries, transmission, substations, utility services, as well as solar. Initiatives are aimed at capturing additional market share and expanding into new markets.

New Accounting Standards

For information regarding new accounting standards, see Item 8 – Note 1, which is incorporated herein by reference.

Critical Accounting Policies Involving Significant Estimates

The Company has prepared its financial statements in conformity with GAAP. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities, at the date of the financial statements as well as the reported amounts of revenues and expenses during the reporting period. The Company's significant accounting policies are discussed in Item 8 – Note 1.

Estimates are used for items such as impairment testing of long-lived assets, goodwill and oil and natural gas properties; fair values of acquired assets and liabilities under the acquisition method of accounting; oil and natural gas reserves; aggregate reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments. The Company's critical accounting policies are subject to judgments and uncertainties that affect the application of such policies. As discussed below, the Company's financial position or results of operations may be materially different when reported under different conditions or when using different assumptions in the application of such policies.

As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates. The following critical accounting policies involve significant judgments and estimates.

Oil and natural gas properties

Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The extent, quality and reliability of this data can vary. Other factors used in the reserve estimates are prices, market differentials, estimates of well operating and future development costs, taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

As these estimates change, calculated proved reserves may change. Changes in proved reserve quantities impact the Company's depreciation, depletion and amortization expense since the Company uses the units-of-production method to amortize its oil and natural gas properties. The proved reserves are also used as the basis for the disclosures in Item 8 – Supplementary Financial Information and are the underlying basis of the "ceiling test" for the Company's oil and natural gas properties.

The Company uses the full-cost method of accounting for its exploration and production activities. Under this method, capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, less applicable income taxes. SEC Defined Prices are used to estimate proved reserves and associated future cash flows. The Company hedges a portion of its oil and natural gas production and the effects of the cash flow hedges are used in determining the full-cost ceiling. Judgments and assumptions are made when estimating and valuing proved reserves. There is risk that lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in additional future noncash write-downs of the Company's oil and natural gas properties.

Impairment of long-lived assets and intangibles

The Company reviews the carrying values of its long-lived assets and intangibles, excluding oil and natural gas properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable and at least annually for goodwill.

Goodwill The Company performs its goodwill impairment testing annually in the fourth quarter. In addition, the test is performed on an interim basis whenever events or circumstances indicate that the carrying amount of goodwill may not be recoverable. Examples of such events or circumstances may include a significant adverse change in business climate, weakness in an industry in which the Company's reporting units operate or recent significant cash or operating losses with expectations that those losses will continue.

The goodwill impairment test is a two-step process performed at the reporting unit level. The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which the Company's chief executive officer and other management regularly review the operating results. For more information on the Company's operating segments, see Item 8 – Note 15. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2012, 2011 and 2010, there were no impairment losses recorded. At December 31, 2012, the fair value substantially exceeded the carrying value at all reporting units.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. The weighted average cost of capital, which varies by reporting unit and is in the range of 6 percent to 11 percent, and a long-term growth rate projection of approximately 3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2012. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Long-Lived Assets Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows could negatively affect the fair value of the Company's assets and result in an impairment charge. If an impairment indicator exists for tangible and intangible assets, excluding goodwill, the asset group held and used is tested for recoverability by comparing an estimate of undiscounted future cash flows attributable to the assets compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value.

There is risk involved when determining the fair value of assets, tangible and intangible, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the asset could be different using different estimates and assumptions in the valuation techniques used.

The Company believes its estimates used in calculating the fair value of long-lived assets, including goodwill and identifiable intangibles, are reasonable based on the information that is known when the estimates are made.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The recognition of revenue requires the Company to make estimates and assumptions that affect the reported amounts of revenue. Critical estimates related to the recognition of revenue include costs on construction contracts under the percentage-of-completion method.

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. This method depends largely on the ability to make reasonably dependable estimates related to the extent of progress toward completion of the contract, contract revenues and contract costs. Inasmuch as contract prices are generally set before the work is performed, the estimates pertaining to every project could contain significant unknown risks such as volatile labor, material and fuel costs, weather delays, adverse project site conditions, unforeseen actions by regulatory agencies, performance by subcontractors, job management and relations with project owners. Changes in estimates could have a material effect on the Company's results of operations, financial position and cash flows.

Several factors are evaluated in determining the bid price for contract work. These include, but are not limited to, the complexities of the job, past history performing similar types of work, seasonal weather patterns, competition and market conditions, job site conditions, work force safety, reputation of the project owner, availability of labor, materials and fuel, project location and project completion dates. As a project commences, estimates are continually monitored and revised as information becomes available and actual costs and conditions surrounding the job become known. If a loss is anticipated on a contract, the loss is immediately recognized.

The Company believes its estimates surrounding percentage-of-completion accounting are reasonable based on the information that is known when the estimates are made. The Company has contract administration, accounting and management control systems in place that allow its estimates to be updated and monitored on a regular basis. Because of the many factors that are evaluated in determining bid prices, it is inherent that the Company's estimates have changed in the past and will continually change in the future as new information becomes available for each job. There were no material changes in contract estimates at the individual contract level in 2012.

Pension and other postretirement benefits

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to these plans. Costs of providing pension and other postretirement benefits bear the risk of change, as they are dependent upon numerous factors based on assumptions of future conditions.

The Company makes various assumptions when determining plan costs, including the current discount rates and the expected long-term return on plan assets, the rate of compensation increases and healthcare cost trend rates. In selecting the expected long-term return on plan assets, which is considered to be one of the key variables in determining benefit expense or income, the Company considers historical returns, current market conditions and expected future market trends, including changes in interest rates and equity and bond market performance. Another key variable in determining benefit expense or income is the discount rate. In selecting the discount rate, the Company matches forecasted future cash flows of the pension and postretirement plans to a yield curve which consists of a hypothetical portfolio of high-quality corporate bonds with varying maturity dates, as well as other factors, as a basis. The Company's pension and other postretirement benefit plan assets are primarily made up of equity and fixed-income investments. Fluctuations in actual equity and bond market returns as well as changes in general interest rates may result in increased or decreased pension and other postretirement benefit costs in the future. Management estimates the rate of compensation increase based on long-term assumed wage increases and the healthcare cost trend rates are determined by historical and future trends. The Company estimates that a 50 basis point decrease in the discount rate or in the expected return on plan assets would each increase expense by less than $1.0 million (after tax) for the year ended December 31, 2012.

The Company believes the estimates made for its pension and other postretirement benefits are reasonable based on the information that is known when the estimates are made. These estimates and assumptions are subject to a number of variables and are expected to change in the future. Estimates and assumptions will be affected by changes in the discount rate, the expected long-term return on plan assets, the rate of compensation increase and healthcare cost trend rates. The Company plans to continue to use its current methodologies to determine plan costs. For additional information on the assumptions used in determining plan costs, see Item 8 – Note 16.

Income taxes

Income taxes require significant judgments and estimates including the determination of income tax expense, deferred tax assets and liabilities and, if necessary, any valuation allowances that may be required for deferred tax assets and accruals for uncertain tax positions. The effective income tax rate is subject to variability from period to period as a result of changes in federal and state income tax rates and/or changes in tax laws. In addition, the effective tax rate may be affected by other changes including the allocation of property, payroll and revenues between states. The Company estimates that a one percent change in the effective tax rate would affect the income tax benefit by less than $500,000 for the year ended December 31, 2012.

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Tax positions taken or expected to be taken in an income tax return are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

The Company believes its estimates surrounding income taxes are reasonable based on the information that is known when the estimates are made.

Liquidity and Capital Commitments

At December 31, 2012, the Company had cash and cash equivalents of $49.0 million and available capacity of $398.6 million under the outstanding credit facilities of the Company and its subsidiaries. The Company expects to meet its obligations for debt maturing within one year from various sources, including internally generated funds; the Company's credit facilities, as described later; and through the issuance of long-term debt and the Company's equity securities.

Cash flows

Operating activities The changes in cash flows from operating activities generally follow the results of operations as discussed in Financial and Operating Data and also are affected by changes in working capital.

Cash flows provided by operating activities in 2012 decreased $41.9 million from the comparable 2011 period, largely due to higher working capital requirements of $82.6 million, primarily at the exploration and production business and the electric and natural gas distribution businesses. Excluding working capital requirements, the Company experienced increased cash flows from operating activities primarily at the construction services business. In addition, excluding the effect of the write-downs of oil and natural gas properties, the decrease was partially offset by higher deferred income taxes of $18.5 million, largely due to increased capital expenditures at the exploration and production business.

Cash flows provided by operating activities in 2011 increased $75.0 million from the comparable prior period. The increase was primarily due to higher deferred income taxes of $52.3 million, largely the result of bonus depreciation, as well as lower working capital requirements of $15.6 million, primarily at the electric and natural gas distribution businesses.

Investing activities Cash flows used in investing activities in 2012 increased $423.4 million from the comparable prior period primarily due to higher ongoing capital expenditures of $375.9 million, largely at the exploration and production and electric and natural gas distribution businesses, as well as increased acquisition-related capital expenditures at the pipeline and energy services business. Lower investments partially offset the increase in cash flows used in investing activities.

Cash flows used in investing activities in 2011 increased $56.6 million from the comparable prior period due to lower proceeds from the sale of the Company's equity method investments in the Brazilian Transmission Lines of $66.3 million, increased ongoing capital expenditures of $47.7 million, largely at the construction materials and contracting business, as well as lower proceeds from the sale or disposition of properties and other of $36.3 million, largely at the exploration and production business. Partially offsetting the increase in cash flows used in investing activities was lower cash used for acquisitions of $104.7 million, primarily at the exploration and production business.

Financing activities Cash flows provided by financing activities in 2012 increased $410.8 million from the comparable period in 2011, primarily due to higher issuance of long-term debt and short-term borrowings of $467.7 million and $20.1 million, respectively, as well as lower repayment of short-term borrowings of $20.0 million. Partially offsetting the increase in cash flows provided by financing activities was higher repayment of long-term debt of $53.6 million, as well as higher dividends paid of $36.4 million resulting from the Company accelerating the payment date for the quarterly common stock dividend to December 31, 2012 from January 1, 2013.

Cash flows used in financing activities in 2011 increased $124.4 million from the comparable prior period, largely resulting from higher repayment of long-term debt and short-term borrowings of $71.5 million and $9.7 million, respectively, as well as lower issuance of short-term borrowings and long-term debt of $20.0 million and $19.9 million, respectively.

Defined benefit pension plans

The Company has qualified noncontributory defined benefit pension plans for certain employees. Plan assets consist of investments in equity and fixed-income securities. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to the pension plans. Actuarial assumptions include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as determined by the Company within certain guidelines. At December 31, 2012, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $149.9 million. Pretax pension expense reflected in the years ended December 31, 2012, 2011 and 2010, was $204,000, $3.7 million and $1.0 million, respectively. The Company's pension expense is currently projected to be approximately $3.5 million to $4.5 million in 2013. Funding for the pension plans is actuarially determined. The minimum required contributions for 2012, 2011 and 2010 were approximately $16.1 million, $9.3 million and $6.4 million, respectively. For more information on the Company's pension plans, see Item 8 – Note 16.

Capital expenditures

The Company's capital expenditures for 2010 through 2012 and as anticipated for 2013 through 2015 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated*		
	2010	2011	**2012**	2013	2014	2015
			(In millions)			
Capital expenditures:						
Electric	$ 86	$ 52	**$ 112**	$154	$149	$ 96
Natural gas distribution	75	71	**130**	98	117	100
Pipeline and energy services**	14	45	**134**	105	109	91
Exploration and production	356	273	**554**	400	402	422
Construction materials and contracting	26	52	**45**	43	62	52
Construction services	15	10	**15**	13	14	13
Other	2	19	**1**	2	1	3
Net proceeds from sale or disposition of property and other	(79)	(41)	**(57)**	(8)	(9)	(3)
Net capital expenditures	495	481	**934**	807	845	774
Retirement of long-term debt	14	85	**139**	134	9	267
	$509	$566	**$1,073**	$941	$854	$1,041

* The Company continues to evaluate potential future acquisitions and other growth opportunities which are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the above estimates.

** 2012 includes a 50 percent undivided interest in natural gas and oil midstream assets, as discussed in Item 8 – Note 2. 2013 – 2015 includes the Company's estimated share of certain capital expenditures related to the planned diesel topping plant, as discussed in Prospective Information and Item 8 – Note 20.

Capital expenditures for 2012, 2011 and 2010 in the preceding table include noncash transactions, including capital expenditure-related accounts payable. The net noncash transactions were $33.7 million in 2012, $24.0 million in 2011 and $17.5 million in 2010.

The 2012 capital expenditures, including those for the retirement of long-term debt, were met from internal sources and the issuance of long-term debt and the Company's equity securities. Estimated capital expenditures for the years 2013 through 2015 include those for:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline, gathering and other midstream projects
- Further development of existing properties, acquisition of additional leasehold acreage and exploratory drilling at the exploration and production segment
- Power generation and transmission opportunities, including certain costs for additional electric generating capacity
- Environmental upgrades
- Other growth opportunities, including the planned diesel topping plant at the pipeline and energy services segment

The Company continues to evaluate potential future acquisitions and other growth opportunities; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates in the preceding table. It is anticipated that all of the funds required for capital expenditures and retirement of long-term debt for the years 2013 through 2015 will be met from various sources, including internally generated funds; the Company's credit facilities, as described later; and through the issuance of long-term debt and the Company's equity securities.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2012. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued. For additional information on the covenants, certain other conditions and cross-default provisions, see Item 8 – Note 9.

The following table summarizes the outstanding credit facilities of the Company and its subsidiaries at December 31, 2012:

Company	Facility	Facility Limit	Amount Outstanding	Letters of Credit	Expiration Date
			(In millions)		
MDU Resources Group, Inc.	Commercial paper/ Revolving credit agreement (a)	$125.0	$ 76.0 (b)	$ –	10/4/17
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (c)	$ 2.0	$ –	12/27/13
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (d)	$ 26.2	$ –	8/11/13
Centennial Energy Holdings, Inc.	Commercial paper/ Revolving credit agreement (e)	$500.0	$217.0 (b)	$20.2 (f)	6/8/17

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $125 million (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(d) Certain provisions allow for increased borrowings, up to a maximum of $80 million.
(e) The $500 million commercial paper program is supported by a revolving credit agreement with various banks totaling $500 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $650 million). There were no amounts outstanding under the credit agreement.
(f) The outstanding letters of credit, as discussed in Item 8 – Note 19, reduce amounts available under the credit agreement.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements. The commercial paper borrowings may vary during the period, largely the result of fluctuations in working capital requirements due to the seasonality of the construction businesses.

The following includes information related to the preceding table.

MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. The commercial paper borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The Company's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in the Company's credit ratings have not limited, nor are currently expected to limit, the Company's ability to access the capital markets. If the Company were to experience a downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

Prior to the maturity of the credit agreement, the Company expects that it will negotiate the extension or replacement of this agreement. If the Company is unable to successfully negotiate an extension of, or replacement for, the credit agreement, or if the fees on this facility become too expensive, which the Company does not currently anticipate, the Company would seek alternative funding.

The Company's coverage of fixed charges including preferred stock dividends was 4.0 times for the 12 months ended December 31, 2011. Due to the $246.8 million after-tax noncash write-downs of oil and natural gas properties in 2012, earnings were insufficient by $51.2 million to cover fixed charges for the 12 months ended December 31, 2012. If the $246.8 million after-tax noncash write-downs were excluded, the coverage of fixed charges including preferred stock dividends would have been 4.4 times for the 12 months ended December 31, 2012.

The coverage of fixed charges including preferred stock dividends, that excludes the effect of the after-tax noncash write-downs of oil and natural gas properties is a non-GAAP financial measure. The Company believes that this non-GAAP financial measure is useful because the write-downs excluded are not indicative of the Company's cash flows available to meets its fixed charges obligations. The presentation of this additional information is not meant to be considered a substitute for the financial measure prepared in accordance with GAAP.

Common stockholders' equity as a percent of total capitalization was 60 percent and 66 percent at December 31, 2012 and 2011, respectively. This ratio is calculated as the Company's common stockholders' equity, divided by the Company's total capital. Total capital is the Company's total debt, including short-term borrowings and long-term debt due within one year, plus stockholders' equity. This ratio indicates how a company is financing its operations, as well as its financial strength.

The Company currently has a shelf registration statement on file with the SEC, under which the Company may issue and sell any combination of common stock and debt securities. The Company may sell all or a portion of such securities if warranted by market conditions and the Company's capital requirements. Any public offer and sale of such securities will be made only by means of a prospectus meeting the requirements of the Securities Act and the rules and regulations thereunder. The Company's board of directors currently has authorized the issuance and sale of up to an aggregate of $1.0 billion worth of such securities. The Company's board of directors reviews this authorization on a periodic basis and the aggregate amount of securities authorized may be increased in the future.

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in Centennial's credit ratings have not limited, nor are currently expected to limit, Centennial's ability to access the capital markets. If Centennial were to experience a downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

Prior to the maturity of the Centennial credit agreement, Centennial expects that it will negotiate the extension or replacement of this agreement, which provides credit support to access the capital markets. In the event Centennial is unable to successfully negotiate this agreement, or in the event the fees on this facility become too expensive, which Centennial does not currently anticipate, it would seek alternative funding.

Off balance sheet arrangements

In connection with the sale of the Brazilian Transmission Lines, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines. For more information, see Item 8 – Note 4.

Centennial continues to guarantee CEM's obligations under a construction contract for an electric generating facility near Hobbs, New Mexico. For more information, see Item 8 – Note 19.

Contractual obligations and commercial commitments

For more information on the Company's contractual obligations on derivative instruments, long-term debt, operating leases and purchase commitments, see Item 8 – Notes 7, 9 and 19. At December 31, 2012, the Company's commitments under these obligations were as follows:

	2013	2014	2015	2016	2017	Thereafter	Total
				(In millions)			
Long-term debt	$134.1	$ 9.3	$266.5	$288.5	$336.4	$ 710.2	$1,745.0
Estimated interest payments*	83.3	77.1	73.1	52.4	41.3	325.0	652.2
Operating leases	32.2	22.5	13.1	9.1	5.1	36.0	118.0
Purchase commitments	494.9	261.4	150.4	92.3	70.0	857.5	1,926.5
Interest rate derivatives	6.3	–	–	–	–	–	6.3
	$750.8	$370.3	$503.1	$442.3	$452.8	$1,928.7	$4,448.0

* Estimated interest payments are calculated based on the applicable rates and payment dates.

At December 31, 2012, the Company had total liabilities of $102.5 million related to asset retirement obligations that are excluded from the table above. Of the total asset retirement obligations, the current portion was approximately $22.8 million at December 31, 2012, and was included in other accrued liabilities on the Consolidated Balance Sheet. The remainder, which constitutes the long-term portion of asset retirement obligations, was included in other liabilities on the Consolidated Balance Sheet. Due to the nature of these obligations, the Company cannot determine precisely when the payments will be made to settle these obligations. For more information, see Item 8 – Note 10.

Not reflected in the previous table are $14.9 million in uncertain tax positions. For more information, see Item 8 – Note 14.

The Company's minimum funding requirements for its defined benefit pension plans for 2013, which are not reflected in the previous table, are $12.6 million. For information on potential contributions above the minimum funding requirements, see Item 8 – Note 16.

The Company's multiemployer plan contributions are based on union employee payroll, which cannot be determined in advance for future periods. The Company may also be required to make additional contributions to its multiemployer plans as a result of their funded status. For more information, see Item 1A – Risk Factors and Item 8 – Note 16.

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Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2012, 2011 or 2010.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company is exposed to the impact of market fluctuations associated with commodity prices, interest rates and foreign currency. The Company has policies and procedures to assist in controlling these market risks and utilizes derivatives to manage a portion of its risk.

For more information on derivatives and the Company's derivative policies and procedures, see Item 8 – Consolidated Statements of Comprehensive Income and Notes 1 and 7.

Commodity price risk

Fidelity utilizes derivative instruments to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas and basis differentials on forecasted sales of oil and natural gas production. Cascade periodically utilizes derivative instruments to manage a portion of their regulated natural gas supply portfolio in order to manage fluctuations in the price of natural gas.

The following table summarizes derivative agreements entered into by Fidelity as of December 31, 2012. These agreements call for Fidelity to receive fixed prices and pay variable prices.

	(Forward notional volume and fair value in thousands)		
	Weighted Average Fixed Price (Per Bbl/MMBtu)	Forward Notional Volume (Bbl/MMBtu)	Fair Value
Oil swap agreements maturing in 2013	$99.83	1,825	$12,038
Natural gas swap agreements maturing in 2013	$ 3.89	10,950	$ 3,753
	Weighted Average Floor/Ceiling Price (Per Bbl)	Forward Notional Volume (Bbl)	Fair Value
Oil collar agreements maturing in 2013	$92.50/$107.03	730	$ 2,513

The following table summarizes derivative agreements entered into by Fidelity and Cascade as of December 31, 2011. These agreements call for Fidelity to receive fixed prices and pay variable prices, and for Cascade to receive variable prices and pay fixed prices.

	(Forward notional volume and fair value in thousands)		
	Weighted Average Fixed Price (Per Bbl/MMBtu)	Forward Notional Volume (Bbl/MMBtu)	Fair Value
Fidelity			
Natural gas swap agreements maturing in 2012	$ 5.37	10,797	$ 22,970
Natural gas basis swap agreements maturing in 2012	$ .41	3,477	$ (801)
Oil swap agreements maturing in 2012	$101.34	1,464	$ 3,694
Oil swap agreements maturing in 2013	$ 95.15	365	$ (229)
Cascade			
Natural gas swap agreement maturing in 2012	$ 4.47	305	$ (437)
	Weighted Average Floor/Ceiling Price (Per Bbl)	Forward Notional Volume (Bbl)	Fair Value
Fidelity			
Oil collar agreements maturing in 2012	$81.25/$95.88	1,464	$(10,904)
Oil collar agreements maturing in 2013	$92.50/$107.03	730	$ 2,061

Interest rate risk

The Company uses fixed and variable rate long-term debt to partially finance capital expenditures and mandatory debt retirements. These debt agreements expose the Company to market risk related to changes in interest rates. The Company manages this risk by taking advantage of market conditions when timing the placement of long-term or permanent financing. The Company from time to time uses interest rate swap agreements to manage a portion of the Company's interest rate risk and may take advantage of such agreements in the future to minimize such risk.

Centennial entered into interest rate swap agreements to manage a portion of its interest rate exposure on the forecasted issuance on long-term debt. The agreements call for Centennial to receive payments from or make payments to counterparties based on the difference between fixed and variable rates as specified by the interest rate swap agreements.

The following table summarizes derivative instruments entered into by Centennial as of December 31, 2012. The agreements call for Centennial to receive variable rates and pay fixed rates.

	(Notional amount and fair value in thousands)		
	Weighted Average Fixed Interest Rate	Notional Amount	Fair Value
Interest rate swap agreements with mandatory termination dates in 2013	3.22%	$50,000	$(6,255)

The following table summarizes derivative instruments entered into by Centennial as of December 31, 2011. The agreements call for Centennial to receive variable rates and pay fixed rates.

	(Notional amount and fair value in thousands)		
	Weighted Average Fixed Interest Rate	Notional Amount	Fair Value
Interest rate swap agreement with mandatory termination date in 2012	3.15%	$10,000	$ (827)
Interest rate swap agreements with mandatory termination dates in 2013	3.22%	$50,000	$(3,935)

The following table shows the amount of debt, including current portion, and related weighted average interest rates, both by expected maturity dates, as of December 31, 2012.

	2013	2014	2015	2016	2017	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$134.1	$9.3	$266.5	$288.5	$ 43.4	$710.2	$1,452.0	$1,595.1
Weighted average interest rate	6.2%	6.9%	5.7%	6.4%	6.3%	5.4%	5.8%	–
Variable rate	–	–	–	–	$293.0	–	$ 293.0	$ 293.0
Weighted average interest rate	–	–	–	–	.5%	–	.5%	–

Foreign currency risk

The Company's equity method investment in ECTE is exposed to market risks from changes in foreign currency exchange rates between the U.S. dollar and the Brazilian Real. For more information, see Item 8 – Note 4. At December 31, 2012 and 2011, the Company had no outstanding foreign currency hedges.

Item 8. Financial Statements and Supplementary Data

Management's Report on Internal Control Over Financial Reporting

The management of MDU Resources Group, Inc. 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. The Company's internal control system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. 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 the Company's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework.*

Based on our evaluation under the framework in *Internal Control-Integrated Framework*, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2012.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2012, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

David L. Goodin
President and Chief Executive Officer

Doran N. Schwartz
Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of MDU Resources Group, Inc.

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income, common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2012. Our audits also included the financial statement schedules listed in the Index at Item 15. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of MDU Resources Group, Inc. and subsidiaries as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 28, 2013

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of MDU Resources Group, Inc.

We have audited the internal control over financial reporting of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2012, based on criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. 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, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit 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. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2012 of the Company and our report dated February 28, 2013 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 28, 2013

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Consolidated Statements of Income

Years ended December 31,	2012	2011	2010
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and pipeline and energy services	**$1,131,626**	$1,343,714	$1,359,028
Exploration and production, construction materials and contracting, construction services and other	**2,943,805**	2,706,778	2,550,667
Total operating revenues	**4,075,431**	4,050,492	3,909,695
Operating expenses:			
Fuel and purchased power	**72,380**	64,485	63,065
Purchased natural gas sold	**425,220**	572,187	567,806
Operation and maintenance:			
Electric, natural gas distribution and pipeline and energy services	**254,194**	275,866	291,524
Exploration and production, construction materials and contracting, construction services and other	**2,377,285**	2,215,269	2,084,377
Depreciation, depletion and amortization	**359,205**	343,395	328,843
Taxes, other than income	**176,140**	172,923	163,353
Write-downs of oil and natural gas properties (Note 1)	**391,800**	–	–
Total operating expenses	**4,056,224**	3,644,125	3,498,968
Operating income	**19,207**	406,367	410,727
Earnings from equity method investments	**5,383**	4,693	30,816
Other income	**6,642**	6,520	8,018
Interest expense	**76,699**	81,354	83,011
Income (loss) before income taxes	**(45,467)**	336,226	366,550
Income taxes	**(31,146)**	110,274	122,530
Income (loss) from continuing operations	**(14,321)**	225,952	244,020
Income (loss) from discontinued operations, net of tax (Note 3)	**13,567**	(12,926)	(3,361)
Net income (loss)	**(754)**	213,026	240,659
Dividends declared on preferred stocks	**685**	685	685
Earnings (loss) on common stock	**$ (1,439)**	$ 212,341	$ 239,974
Earnings (loss) per common share – basic:			
Earnings (loss) before discontinued operations	**$ (.08)**	$ 1.19	$ 1.29
Discontinued operations, net of tax	**.07**	(.07)	(.01)
Earnings (loss) per common share – basic	**$ (.01)**	$ 1.12	$ 1.28
Earnings (loss) per common share – diluted:			
Earnings (loss) before discontinued operations	**$ (.08)**	$ 1.19	$ 1.29
Discontinued operations, net of tax	**.07**	(.07)	(.02)
Earnings (loss) per common share – diluted	**$ (.01)**	$ 1.12	$ 1.27
Dividends declared per common share	**$ .6750**	$ .6550	$ .6350
Weighted average common shares outstanding – basic	**188,826**	188,763	188,137
Weighted average common shares outstanding – diluted	**188,826**	188,905	188,229

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Comprehensive Income

Years ended December 31,	2012	2011	2010
		(In thousands)	
Net income (loss)	**$ (754)**	$213,026	$240,659
Other comprehensive loss:			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $4,829, $4,683 and $(1,867) in 2012, 2011 and 2010, respectively	**8,497**	7,900	(3,077)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $5,141, $0 and $(2,305) in 2012, 2011 and 2010, respectively	**8,754**	–	(3,750)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	**(257)**	7,900	673
Postretirement liability adjustment:			
Postretirement liability losses arising during the period, net of tax of $(2,060), $(14,205) and $(4,112) in 2012, 2011 and 2010, respectively	**(3,106)**	(23,473)	(6,528)
Amortization of postretirement liability losses included in net periodic benefit cost, net of tax of $1,379, $632 and $503 in 2012, 2011 and 2010, respectively	**2,079**	1,046	798
Postretirement liability adjustment	**(1,027)**	(22,427)	(5,730)
Foreign currency translation adjustment, net of tax of $(294), $(832) and $(3,486) in 2012, 2011 and 2010, respectively	**(473)**	(1,295)	(5,371)
Net unrealized gains on available-for-sale investments, net of tax of $20 and $44 in 2012 and 2011, respectively	**37**	82	–
Other comprehensive loss	**(1,720)**	(15,740)	(10,428)
Comprehensive income (loss)	**$(2,474)**	$197,286	$230,231

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Balance Sheets

December 31,	2012	2011
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	**$ 49,042**	$ 162,772
Receivables, net	**678,123**	646,251
Inventories	**317,415**	274,205
Deferred income taxes	**22,846**	40,407
Commodity derivative instruments	**18,304**	27,687
Prepayments and other current assets	**42,351**	43,316
Total current assets	**1,128,081**	1,194,638
Investments	**103,243**	109,424
Property, plant and equipment (Note 1)	**8,107,751**	7,646,222
Less accumulated depreciation, depletion and amortization	**3,608,912**	3,361,208
Net property, plant and equipment	**4,498,839**	4,285,014
Deferred charges and other assets:		
Goodwill (Note 5)	**636,039**	634,931
Other intangible assets, net (Note 5)	**17,129**	20,843
Other	**299,160**	311,275
Total deferred charges and other assets	**952,328**	967,049
Total assets	**$6,682,491**	$6,556,125
Liabilities and Stockholders' Equity		
Current liabilities:		
Short-term borrowings (Note 9)	**$ 28,200**	$ –
Long-term debt due within one year	**134,108**	139,267
Accounts payable	**388,015**	337,228
Taxes payable	**46,475**	70,176
Dividends payable	**171**	31,794
Accrued compensation	**48,448**	47,804
Commodity derivative instruments	**–**	13,164
Other accrued liabilities	**204,698**	259,320
Total current liabilities	**850,115**	898,753
Long-term debt (Note 9)	**1,610,867**	1,285,411
Deferred credits and other liabilities:		
Deferred income taxes	**755,102**	769,166
Other liabilities	**818,159**	827,228
Total deferred credits and other liabilities	**1,573,261**	1,596,394
Commitments and contingencies (Notes 16, 18 and 19)		
Stockholders' equity:		
Preferred stocks (Note 11)	**15,000**	15,000
Common stockholders' equity:		
Common stock (Note 12)		
Authorized – 500,000,000 shares, $1.00 par value		
Issued – 189,369,450 shares in 2012 and 189,332,485 shares in 2011	**189,369**	189,332
Other paid-in capital	**1,039,080**	1,035,739
Retained earnings	**1,457,146**	1,586,123
Accumulated other comprehensive loss	**(48,721)**	(47,001)
Treasury stock at cost – 538,921 shares	**(3,626)**	(3,626)
Total common stockholders' equity	**2,633,248**	2,760,567
Total stockholders' equity	**2,648,248**	2,775,567
Total liabilities and stockholders' equity	**$6,682,491**	$6,556,125

The accompanying notes are an integral part of these consolidated financial statements.

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Consolidated Statements of Common Stockholders' Equity

Years ended December 31, 2012, 2011 and 2010

	Common Stock Shares	Common Stock Amount	Other Paid-in Capital	Retained Earnings	Accumulated Other Compre-hensive Loss	Treasury Stock Shares	Treasury Stock Amount	Total
				(In thousands, except shares)				
Balance at December 31, 2009	188,389,265	$188,389	$1,015,678	$1,377,039	$(20,833)	(538,921)	$(3,626)	$2,556,647
Net income	–	–	–	240,659	–	–	–	240,659
Other comprehensive loss	–	–	–	–	(10,428)	–	–	(10,428)
Dividends declared on preferred stocks	–	–	–	(685)	–	–	–	(685)
Dividends declared on common stock	–	–	–	(119,574)	–	–	–	(119,574)
Stock-based compensation	426,610	427	8,267	–	–	–	–	8,694
Tax benefit on stock-based compensation	–	–	924	–	–	–	–	924
Issuance of common stock	85,504	85	1,480	–	–	–	–	1,565
Balance at December 31, 2010	188,901,379	188,901	1,026,349	1,497,439	(31,261)	(538,921)	(3,626)	2,677,802
Net income	–	–	–	213,026	–	–	–	213,026
Other comprehensive loss	–	–	–	–	(15,740)	–	–	(15,740)
Dividends declared on preferred stocks	–	–	–	(685)	–	–	–	(685)
Dividends declared on common stock	–	–	–	(123,657)	–	–	–	(123,657)
Stock-based compensation	423,591	424	10,164	–	–	–	–	10,588
Net tax deficit on stock-based compensation	–	–	(909)	–	–	–	–	(909)
Issuance of common stock	7,515	7	135	–	–	–	–	142
Balance at December 31, 2011	189,332,485	189,332	1,035,739	1,586,123	(47,001)	(538,921)	(3,626)	2,760,567
Net loss	–	–	–	(754)	–	–	–	(754)
Other comprehensive loss	–	–	–	–	(1,720)	–	–	(1,720)
Dividends declared on preferred stocks	–	–	–	(685)	–	–	–	(685)
Dividends declared on common stock	–	–	–	(127,538)	–	–	–	(127,538)
Stock-based compensation	25,743	26	5,094	–	–	–	–	5,120
Net tax deficit on stock-based compensation	–	–	(1,958)	–	–	–	–	(1,958)
Issuance of common stock	11,222	11	205	–	–	–	–	216
Balance at December 31, 2012	**189,369,450**	**$189,369**	**$1,039,080**	**$1,457,146**	**$(48,721)**	**(538,921)**	**$(3,626)**	**$2,633,248**

The accompanying notes are an integral part of these consolidated financial statements.

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Consolidated Statements of Cash Flows

Years ended December 31,	2012	2011	2010
		(In thousands)	
Operating activities:			
Net income (loss)	**$ (754)**	$ 213,026	$ 240,659
Income (loss) from discontinued operations, net of tax	**13,567**	(12,926)	(3,361)
Income (loss) from continuing operations	**(14,321)**	225,952	244,020
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**359,205**	343,395	328,843
Earnings, net of distributions, from equity method investments	**(618)**	(2,111)	(26,158)
Deferred income taxes	**(7,503)**	118,925	66,585
Write-downs of oil and natural gas properties (Note 1)	**391,800**	–	–
Changes in current assets and liabilities, net of acquisitions:			
Receivables	**(13,416)**	(30,452)	(59,037)
Inventories	**(42,334)**	(24,226)	(4,728)
Other current assets	**297**	7,729	(7,424)
Accounts payable	**6,352**	(12,263)	17,833
Other current liabilities	**(59,001)**	33,738	12,289
Other noncurrent changes	**(33,041)**	(33,365)	(20,271)
Net cash provided by continuing operations	**587,420**	627,322	551,952
Net cash used in discontinued operations	**(2,680)**	(674)	(319)
Net cash provided by operating activities	**584,740**	626,648	551,633
Investing activities:			
Capital expenditures	**(872,920)**	(497,000)	(449,282)
Acquisitions, net of cash acquired	**(67,261)**	(157)	(104,812)
Net proceeds from sale or disposition of property and other	**40,110**	40,107	76,386
Investments	**9,725**	(10,302)	704
Proceeds from sale of equity method investments	**2,394**	2,807	69,060
Net cash used in continuing operations	**(887,952)**	(464,545)	(407,944)
Net cash provided by discontinued operations	**–**	–	–
Net cash used in investing activities	**(887,952)**	(464,545)	(407,944)
Financing activities:			
Issuance of short-term borrowings	**20,100**	–	20,000
Repayment of short-term borrowings	**–**	(20,000)	(10,300)
Issuance of long-term debt	**467,957**	300	20,200
Repayment of long-term debt	**(138,775)**	(85,151)	(13,668)
Proceeds from issuance of common stock	**88**	5,744	4,972
Dividends paid	**(159,768)**	(123,323)	(119,157)
Excess tax benefit on stock-based compensation	**26**	1,239	1,186
Net cash provided by (used in) continuing operations	**189,628**	(221,191)	(96,767)
Net cash provided by discontinued operations	**–**	–	–
Net cash provided by (used in) financing activities	**189,628**	(221,191)	(96,767)
Effect of exchange rate changes on cash and cash equivalents	**(146)**	(214)	38
Increase (decrease) in cash and cash equivalents	**(113,730)**	(59,302)	46,960
Cash and cash equivalents – beginning of year	**162,772**	222,074	175,114
Cash and cash equivalents – end of year	**$ 49,042**	$ 162,772	$ 222,074

The accompanying notes are an integral part of these consolidated financial statements.

Notes to Consolidated Financial Statements

Note 1 – Summary of Significant Accounting Policies

Basis of presentation

The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline and energy services, exploration and production, construction materials and contracting, construction services and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Exploration and production, construction materials and contracting, construction services and other are nonregulated. For further descriptions of the Company's businesses, see Note 15. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by the Company's nonregulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

Depreciation, depletion and amortization expense is reported separately on the Consolidated Statements of Income and therefore is excluded from the other line items within operating expenses.

Management has also evaluated the impact of events occurring after December 31, 2012, up to the date of issuance of these consolidated financial statements.

Cash and cash equivalents

The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. The total balance of receivables past due 90 days or more was $34.3 million and $29.8 million as of December 31, 2012 and 2011, respectively. For more information, see Percentage-of-completion method in this note.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of December 31, 2012 and 2011, was $10.8 million and $12.4 million, respectively.

Inventories and natural gas in storage

Inventories, other than natural gas in storage for the Company's regulated operations, were stated at the lower of average cost or market value. Natural gas in storage for the Company's regulated operations is generally carried at average cost, or cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories. Inventories at December 31 consisted of:

	2012	2011
	(In thousands)	
Aggregates held for resale	**$ 87,715**	$ 78,518
Materials and supplies	**69,390**	61,611
Natural gas in storage (current)	**29,030**	36,578
Asphalt oil	**67,480**	32,335
Merchandise for resale	**31,172**	32,165
Other	**32,628**	32,998
Total	**$317,415**	$274,205

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $49.7 million and $50.3 million at December 31, 2012 and 2011, respectively.

Investments

The Company's investments include its equity method investments as discussed in Note 4, the cash surrender value of life insurance policies, an insurance investment contract, mortgage-backed securities and U.S. Treasury securities. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. The Company has elected to measure its investment in the insurance investment contract at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. The Company has not elected the fair value option for its mortgage-backed securities and U.S. Treasury securities and, as a result, the unrealized gains and losses on these investments are recorded in accumulated other comprehensive income (loss). For more information, see Notes 8 and 16.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for exploration and production properties as described in Oil and natural gas properties in this note, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, at the exploration and production segment only on costs that have been excluded from the full cost amortization pool and on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized for the years ended December 31 were as follows:

	2012	2011	2010
		(In thousands)	
Interest capitalized	**$8,659**	$10,821	$9,753
AFUDC – borrowed	**$2,483**	$ 1,666	$2,950
AFUDC – equity	**$4,530**	$ 2,587	$4,896

Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method, and exploration and production properties, which are amortized on the units-of-production method based on total proved reserves. The Company collects removal costs for plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities, which are included in other liabilities.

Property, plant and equipment at December 31 was as follows:

	2012	2011	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	**$ 580,567**	$ 546,783	47
Distribution	**282,424**	255,232	36
Transmission	**190,311**	179,580	44
Other	**97,282**	86,929	14
Natural gas distribution:			
Distribution	**1,329,692**	1,257,360	40
Other	**360,258**	311,506	24
Pipeline and energy services:			
Transmission	**416,186**	386,227	52
Gathering	**42,424**	42,378	19
Storage	**42,554**	41,908	51
Other	**38,493**	36,179	29
Nonregulated:			
Pipeline and energy services:			
Gathering	**259,724**	198,864	16
Other	**17,152**	13,735	10
Exploration and production:			
Oil and natural gas properties	**2,723,356**	2,577,576	*
Other	**41,204**	37,570	8
Construction materials and contracting:			
Land	**126,788**	126,790	–
Buildings and improvements	**73,884**	67,627	19
Machinery, vehicles and equipment	**899,592**	902,136	12
Construction in progress	**11,165**	8,085	–
Aggregate reserves	**393,552**	395,214	**
Construction services:			
Land	**4,723**	4,706	–
Buildings and improvements	**16,563**	15,001	23
Machinery, vehicles and equipment	**100,445**	95,891	7
Other	**8,893**	9,198	4
Other:			
Land	**2,837**	2,837	–
Other	**47,682**	46,910	24
Less accumulated depreciation, depletion and amortization	**3,608,912**	3,361,208	
Net property, plant and equipment	**$4,498,839**	$4,285,014	

* Amortized on the units-of-production method based on total proved reserves at a BOE average rate of $15.28, $12.25 and $10.64 for the years ended December 31, 2012, 2011 and 2010, respectively. Includes oil and natural gas properties accounted for under the full-cost method, of which $191.8 million and $232.5 million were excluded from amortization at December 31, 2012 and 2011, respectively.

** Depleted on the units-of-production method.

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and oil and natural gas properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In 2012, the Company recognized a $1.7 million (after tax) impairment of certain natural gas gathering assets, at the pipeline and energy services segment, due largely to low natural gas prices. No significant impairment losses were recorded in 2011 and 2010. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

The goodwill impairment test is a two-step process performed at the reporting unit level. The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which the Company's chief executive officer and other management regularly review the operating results. For more information on the Company's operating segments, see Note 15. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2012, 2011 and 2010, there were no impairment losses recorded. At December 31, 2012, the fair value substantially exceeded the carrying value at all reporting units.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. The weighted average cost of capital, which varies by reporting unit and is in the range of 6 percent to 11 percent, and a long-term growth rate projection of approximately 3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2012. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Oil and natural gas properties

The Company uses the full-cost method of accounting for its oil and natural gas production activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized and amortized on the units-of-production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized.

Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, less applicable income taxes. Proved reserves and associated future cash flows are determined based on SEC Defined Prices. If capitalized costs, less accumulated amortization and related deferred income taxes, exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter regardless of subsequent price changes.

The Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at September 30, 2012 and December 31, 2012. SEC Defined Prices, adjusted for market differentials, are used to calculate the ceiling test. SEC Defined Prices as of September 30, 2012 and December 31, 2012, were $94.97 per Bbl for NYMEX oil and $2.83 per MMBtu for Henry Hub natural gas and $94.71 per Bbl for NYMEX oil and $2.76 per MMBtu for Henry Hub natural gas, respectively. Accordingly, the Company was required to write down its oil and natural gas producing properties. The noncash write-downs amounted to $160.1 million and $231.7 million ($100.9 million and $145.9 million after tax) for the three months ended September 30, 2012 and December 31, 2012, respectively.

The Company hedges a portion of its oil and natural gas production and the effects of the cash flow hedges were used in determining the full-cost ceiling. The Company would have recognized additional write-downs of its oil and natural gas properties of $19.5 million ($12.3 million after tax) at September 30, 2012, and $20.8 million ($13.1 million after tax) at December 31, 2012, if the effects of cash flow hedges had not been considered in calculating the full-cost ceiling. For more information on the Company's cash flow hedges, see Note 7.

There is risk that lower SEC Defined Prices, market differentials, changes in estimates of proved reserve quantities, unsuccessful results of exploration and development efforts or changes in operating and development costs could result in additional future noncash write-downs of the Company's oil and natural gas properties.

The following table summarizes the Company's oil and natural gas properties not subject to amortization at December 31, 2012, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2012	2011	2010	2009 and prior
			(In thousands)		
Acquisition	$144,521	$26,318	$38,186	$22,142	$57,875
Development	7,415	6,858	399	77	81
Exploration	36,246	34,407	856	643	340
Capitalized interest	3,612	1,297	757	439	1,119
Total costs not subject to amortization	$191,794	$68,880	$40,198	$23,301	$59,415

Costs not subject to amortization as of December 31, 2012, consisted primarily of unevaluated leaseholds and development costs in the Bakken area, the Paradox Basin, Texas properties, the Green River Basin, the Big Horn Basin and Heath Shale. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $85.9 million and $80.2 million at December 31, 2012 and 2011, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from exploration and production properties only on that portion of production sold and allocable to the Company's ownership interest in the related properties. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized. Costs and estimated earnings in excess of billings on uncompleted contracts of $65.0 million and $54.3 million at December 31, 2012 and 2011, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts of $83.2 million and $79.1 million at December 31, 2012 and 2011, respectively, represent billings in excess of revenues recognized and were included in accounts payable. Amounts representing balances billed but not paid by customers under retainage provisions in contracts amounted to $56.3 million and $51.5 million at December 31, 2012 and 2011, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to $54.3 million and $49.3 million at December 31, 2012 and 2011, respectively. The long-term retainage which was included in deferred charges and other assets – other was $2.0 million and $2.2 million at December 31, 2012 and 2011, respectively.

Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions, and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties.

The Company's policy generally allows the hedging of monthly forecasted sales of oil and natural gas production at Fidelity for a period up to 36 months from the time the Company enters into the hedge. The Company's policy requires that interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. The Company's policy allows the hedging of monthly forecasted purchases of natural gas at Cascade and Intermountain for a period up to three years.

The Company's policy requires that each month as physical oil and natural gas production at Fidelity occurs and the commodity is sold, the related portion of the derivative agreement for that month's production must settle with its counterparties. Settlements represent the exchange of cash between the Company and its counterparties based on the notional quantities and prices for each month's physical delivery as specified within the agreements. The fair value of the remaining notional amounts on the derivative agreements is recorded on the balance sheet as an asset or liability measured at fair value. The Company's policy also requires settlement of natural gas derivative instruments at Cascade and Intermountain monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. Accordingly, the Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 7.

The Company's derivative instruments are reflected at fair value. For more information, see Note 8.

Asset retirement obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 10.

Legal costs

The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $35.3 million and $45.1 million at December 31, 2012 and 2011, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $3.0 million and $2.6 million at December 31, 2012 and 2011, respectively, which is included in prepayments and other current assets.

Insurance

Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $1 million per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $1 million per accident or occurrence. These subsidiaries have excess coverage above the primary automobile and general liability policies on a claims first-made and reported basis beyond the deductible levels. The subsidiaries of the Company are retaining losses up to the deductible amounts accrued on the basis of estimates of liability for claims incurred and for claims incurred but not reported.

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Tax positions taken or expected to be taken in an income tax return are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

Foreign currency translation adjustment

The functional currency of the Company's investment in ECTE, as further discussed in Note 4, is the Brazilian Real. Translation from the Brazilian Real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses are translated on a year-to-date basis using an average of the daily exchange rates. Adjustments resulting from such translations are reported as a separate component of other comprehensive income (loss) in common stockholders' equity.

Transaction gains and losses resulting from the effect of exchange rate changes on transactions denominated in a currency other than the functional currency of the reporting entity would be recorded in income.

Earnings (loss) per common share

Basic earnings (loss) per common share were computed by dividing earnings (loss) on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options and performance share awards. Diluted loss per common share for the year ended December 31, 2012, was computed by dividing the loss on common stock by the weighted average number of shares of common stock outstanding during the year. Due to the loss on common stock for the year ended December 31, 2012, the effect of outstanding performance share awards was excluded from the computation of diluted loss per common share as their effect was antidilutive. Common stock outstanding includes issued shares less shares held in treasury. Net income (loss) was the same for both the basic and diluted earnings (loss) per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings (loss) per share calculation was as follows:

	2012	2011	2010
		(In thousands)	
Weighted average common shares outstanding – basic	**188,826**	188,763	188,137
Effect of dilutive stock options and performance share awards	**–**	142	92
Weighted average common shares outstanding – diluted	**188,826**	188,905	188,229
Shares excluded from the calculation of diluted earnings per share	**58**	–	–

Use of estimates

The preparation of financial statements in conformity with GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of long-lived assets, goodwill and oil and natural gas properties; fair values of acquired assets and liabilities under the acquisition method of accounting; oil, NGL and natural gas proved reserves; aggregate reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information

Cash expenditures for interest and income taxes for the years ended December 31 were as follows:

	2012	2011	2010
		(In thousands)	
Interest, net of amount capitalized	**$74,378**	$ 78,133	$80,962
Income taxes paid (refunded), net	**$ 3,277**	$(12,287)	$46,892

Noncash investing transactions at December 31 were as follows:

	2012	2011	2010
		(In thousands)	
Property, plant and equipment additions in accounts payable	**$76,205**	$41,540	$30,895

New accounting standards

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements. The guidance generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the guidance includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This guidance was effective for the Company on January 1, 2012. The guidance required additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Presentation of Comprehensive Income In June 2011, the FASB issued guidance on the presentation of comprehensive income. This guidance eliminates the option of presenting components of other comprehensive income as part of the statement of stockholders' equity. The guidance allows the Company the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB had deferred the effective date for the guidance related to the presentation of reclassifications of items out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. The guidance, except for the portion that was deferred, was effective for the Company on January 1, 2012, and must be applied retrospectively. The guidance requires the Company to present a consolidated statement of comprehensive income as part of its basic financial statements along with other revisions to the disclosures, but it did not impact the Company's results of operations, financial position or cash flows. In February 2013, the FASB issued guidance related to the reclassifications requiring companies to present, either on the face of the consolidated statement of income or in the notes, the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items of net income. The guidance related to reclassifications is effective for the Company on January 1, 2013, and is to be applied prospectively. The guidance will require additional disclosures, however it will not impact the Company's results of operations, financial position or cash flows.

Disclosures about Offsetting Assets and Liabilities In December 2011, the FASB issued guidance on the disclosure requirements related to balance sheet offsetting. The new disclosure requirements relate to the nature of an entity's rights of offset and related arrangements associated with its financial instruments and derivative instruments. The guidance is effective for the Company on January 1, 2013, and must be applied retrospectively. The Company is evaluating the effects of this guidance on disclosures, but it will not impact the Company's results of operations, financial position or cash flows.

Variable interest entities

The Company evaluates its arrangements and contracts with other entities including, but not limited to, fuel contracts to determine if the other party is a variable interest entity and if so, if the Company is the primary beneficiary. The Company follows accounting guidance for variable interest entities which requires consideration of the activities that most significantly impact an entity's financial performance and power to direct those activities, when determining whether the Company is a variable interest entity's primary beneficiary. For more information on variable interest entities, see Note 19.

Comprehensive income (loss)

Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains (losses) on derivative instruments qualifying as hedges, postretirement liability adjustments, foreign currency translation adjustments and gains on available-for-sale investments. For more information on derivative instruments, see Note 7.

The after-tax components of accumulated other comprehensive loss as of December 31, 2012, 2011 and 2010, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Post-retirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gains on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
			(In thousands)		
Balance at December 31, 2010	$(1,625)	$(30,893)	$1,257	$ –	$(31,261)
Current-period other comprehensive loss	7,900	(22,427)	(1,295)	82	(15,740)
Balance at December 31, 2011	6,275	(53,320)	(38)	82	(47,001)
Current-period other comprehensive loss	(257)	(1,027)	(473)	37	(1,720)
Balance at December 31, 2012	**$ 6,018**	**$(54,347)**	**$ (511)**	**$119**	**$(48,721)**

Note 2 – Acquisitions

In 2012, the Company acquired a 50 percent undivided interest in natural gas and oil midstream assets in western North Dakota. The acquisition includes a natural gas processing plant and a natural gas gathering pipeline system, along with an oil gathering system, an oil storage terminal and an oil pipeline. The total purchase consideration for acquisitions was approximately $67.5 million, including the Company's interest in the above facilities and contingent consideration related to an acquisition made prior to 2012. The Company recognizes its proportionate share of the assets, liabilities, revenues and expenses related to the natural gas and oil midstream assets acquisition.

In 2011, contingent consideration, consisting of the Company's common stock and cash, of $298,000 was made with respect to an acquisition made prior to 2011.

In 2010, the Company acquired natural gas properties in the Green River Basin in southwest Wyoming. The total purchase consideration for these properties and contingent consideration with respect to certain other acquisitions made prior to 2010, consisting of the Company's common stock and cash, was $106.4 million.

The acquisitions were accounted for under the acquisition method of accounting and, accordingly, the acquired assets and liabilities assumed have been recorded at their respective fair values as of the date of acquisition. The results of operations of the acquired businesses and properties are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

Note 3 – Discontinued Operations

In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources had agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. The Company incurs legal expenses and has accrued liabilities related to this matter. In the fourth quarter of 2010, the Company established an accrual for an indemnification claim by Bicent. In the fourth quarter of 2011, the Company accrued $21.0 million ($13.0 million after tax) related to the guarantee as a result of an arbitration award against CEM. In 2011, the Company also incurred legal expenses related to this matter and in the first quarter had an income tax benefit related to favorable resolution of certain tax matters. In the second quarter of 2012, discontinued operations reflected the settlement of certain liabilities and estimated insurance recoveries resulting in a net benefit related to this matter. In the fourth quarter of 2012, the Company reversed its previously recorded accrual for the arbitration charge due to a favorable court ruling, which was partially offset by the reversal of estimated insurance recoveries. These items are reflected as discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category. For more information, see Note 19.

Note 4 – Equity Method Investments

Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. The Company's equity method investments at December 31, 2012 and 2011, include ECTE.

In August 2006, MDU Brasil acquired ownership interests in the Brazilian Transmission Lines. The electric transmission lines are primarily in northeastern and southern Brazil. The transmission contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

In 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. In November 2010, the Company completed the sale and recognized a gain of $22.7 million ($13.8 million after tax). The Company's entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE was sold. The remaining interest in ECTE is being purchased over a four-year period. In August 2012 and November 2011, the Company completed the sale of one-fourth of the remaining interest in each year. The Company recognized an immaterial gain in 2012 and a $1.0 million ($600,000 after tax) gain in 2011. The gains are recorded in earnings from equity method investments on the Consolidated Statements of Income. Alusa, CEMIG and CELESC hold the remaining ownership interests in ECTE.

At December 31, 2012 and 2011, the Company's equity method investments had total assets of $129.0 million and $111.1 million, respectively, and long-term debt of $65.5 million and $37.1 million, respectively. The Company's investment in its equity method investments was approximately $6.9 million and $9.2 million, including undistributed earnings of $3.4 million and $3.7 million, at December 31, 2012 and 2011, respectively.

Note 5 – Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2012, were as follows:

	Balance as of January 1, 2012*	Goodwill Acquired During the Year**	Balance as of December 31, 2012*
		(In thousands)	
Natural gas distribution	$345,736	$ –	$345,736
Pipeline and energy services	9,737	–	9,737
Construction materials and contracting	176,290	–	176,290
Construction services	103,168	1,108	104,276
Total	$634,931	$1,108	$636,039

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.

** Includes contingent consideration that was not material related to an acquisition in a prior period.

The changes in the carrying amount of goodwill for the year ended December 31, 2011, were as follows:

	Balance as of January 1, 2011*	Goodwill Acquired During the Year**	Balance as of December 31, 2011*
		(In thousands)	
Natural gas distribution	$345,736	$ –	$345,736
Pipeline and energy services	9,737	–	9,737
Construction materials and contracting	176,290	–	176,290
Construction services	102,870	298	103,168
Total	$634,633	$298	$634,931

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.

** Includes contingent consideration that was not material related to an acquisition in a prior period.

Other amortizable intangible assets at December 31 were as follows:

	2012	2011
	(In thousands)	
Customer relationships	**$ 21,310**	$ 21,702
Accumulated amortization	**(11,701)**	(10,392)
	9,609	11,310
Noncompete agreements	**7,236**	7,685
Accumulated amortization	**(5,326)**	(5,371)
	1,910	2,314
Other	**10,979**	11,442
Accumulated amortization	**(5,369)**	(4,223)
	5,610	7,219
Total	**$ 17,129**	$ 20,843

Amortization expense for intangible assets for the years ended December 31, 2012, 2011 and 2010, was $3.8 million, $3.7 million and $4.2 million, respectively. Estimated amortization expense for intangible assets is $3.7 million in 2013, $3.5 million in 2014, $2.6 million in 2015, $2.2 million in 2016, $1.9 million in 2017 and $3.2 million thereafter.

Note 6 – Regulatory Assets and Liabilities

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	Estimated Recovery Period*	2012	2011
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	**$166,477**	$ 171,492
Deferred income taxes	**	**121,781**	119,189
Manufactured gas plant sites remediation (a)	Up to 5 years	**15,828**	8,150
Plant costs (a)	Over plant lives	**10,348**	10,256
Long-term debt refinancing costs (a)	Up to 25 years	**9,144**	10,112
Taxes recoverable from customers (a)	–	**9,078**	12,433
Costs related to identifying generation development (a)	Up to 14 years	**5,773**	9,817
Other (a) (b)	Largely within 1 year	**12,765**	17,560
Total regulatory assets		**351,194**	359,009
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		**296,037**	289,972
Deferred income taxes**		**82,077**	84,963
Natural gas costs refundable through rate adjustments (d)		**35,328**	45,064
Taxes refundable to customers (c)		**24,212**	31,837
Other (c) (d)		**12,828**	8,393
Total regulatory liabilities		**450,482**	460,229
Net regulatory position		**$ (99,288)**	$(101,220)

* Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.
** Represents deferred income taxes related to regulatory assets and liabilities. The deferred income tax assets are not earning a rate of return.
(a) Included in deferred charges and other assets on the Consolidated Balance Sheets.
(b) Included in prepayments and other current assets on the Consolidated Balance Sheets.
(c) Included in other liabilities on the Consolidated Balance Sheets.
(d) Included in other accrued liabilities on the Consolidated Balance Sheets.
(e) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. Excluding deferred income taxes, as of December 31, 2012 and 2011, approximately $215.6 million and $216.4 million, respectively, of regulatory assets were not earning a rate of return.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of regulatory accounting occurs.

Note 7 – Derivative Instruments

Derivative instruments, including certain derivative instruments embedded in other contracts, are required to be recorded on the balance sheet as either an asset or liability measured at fair value. The Company's policy is to not offset fair value amounts for derivative instruments and, as a result, the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. Changes in the derivative instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would be discontinued and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity. As of December 31, 2012, the Company had no outstanding foreign currency hedges.

The Company evaluates counterparty credit risk on its derivative assets and the Company's credit risk on its derivative liabilities. As of December 31, 2012 and 2011, credit risk was not material.

Cascade

Cascade has historically utilized natural gas swap agreements to manage a portion of their regulated natural gas supply portfolio in order to manage fluctuations in the price of natural gas related to core customers in accordance with authority granted by the WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. As of December 31, 2012, Cascade had no outstanding swap agreements. The fair value of derivative instruments must be estimated as of the end of each reporting period and recorded on the Consolidated Balance Sheets as an asset or a liability. Periodic changes in the fair market value of derivative instruments are recorded on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Gains and losses on the settlements of derivative instruments are recorded as a component of purchased natural gas sold on the Consolidated Statements of Income as they are recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade either pays or receives settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract. For the years ended December 31, 2012 and 2011, the change in the fair market value of the derivative instruments of $437,000 and $8.9 million, respectively, were recorded as a decrease to regulatory assets.

Fidelity

At December 31, 2012, Fidelity held oil swap and collar agreements with total forward notional volumes of 2.6 million Bbl and natural gas swap agreements with total forward notional volumes of 11.0 million MMBtu, a majority of which were designated as cash flow hedging instruments. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas and basis differentials on its forecasted sales of oil and natural gas production.

Centennial

At December 31, 2012, Centennial held interest rate swap agreements with a total notional amount of $50.0 million, which were designated as cash flow hedging instruments. Centennial entered into these interest rate derivative instruments to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt. Centennial's interest rate swap agreements have mandatory termination dates ranging from January through June 2013.

Fidelity and Centennial

The fair value of the derivative instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

There were no components of the derivative instruments' gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur, and there were no such reclassifications.

Gains and losses on the oil and natural gas derivative instruments are reclassified from accumulated other comprehensive income (loss) into operating revenues on the Consolidated Statements of Income at the date the oil and natural gas quantities are settled. The proceeds received for oil and natural gas production are generally based on market prices. Gains and losses on the interest rate derivatives are reclassified from accumulated other comprehensive income (loss) into interest expense on the Consolidated Statements of Income in the same period the hedged item affects earnings. The gains and losses on derivative instruments for the years ended December 31 were as follows:

	2012	2011	2010
		(In thousands)	
Commodity derivatives designated as cash flow hedges:			
Amount of gain (loss) recognized in accumulated other comprehensive loss (effective portion), net of tax	**$10,209**	$10,806	$(3,077)
Amount of gain (loss) reclassified from accumulated other comprehensive loss into operating revenues (effective portion), net of tax	**8,788**	–	(3,720)
Amount of gain (loss) recognized in operating revenues (ineffective portion), before tax	**(730)**	1,827	–
Interest rate derivatives designated as cash flow hedges:			
Amount of loss recognized in accumulated other comprehensive loss (effective portion), net of tax	**(1,712)**	(2,906)	–
Amount of loss reclassified from accumulated other comprehensive loss into interest expense (effective portion), net of tax	**(34)**	–	(30)
Amount of gain (loss) recognized in interest expense (ineffective portion), before tax	**–**	–	–
Commodity derivatives not designated as hedging instruments:			
Amount of gain recognized in operating revenues, before tax	**106**	–	–

As of December 31, 2012, the maximum term of the derivative instruments, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 12 months.

Based on December 31, 2012, fair values, over the next 12 months net gains of approximately $10.4 million (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, subject to changes in oil and natural gas market prices and interest rates, as the hedged transactions affect earnings.

Certain of Fidelity's and Centennial's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates or Centennial fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. The aggregate fair value of Fidelity's and Centennial's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2012, was $6.3 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2012, was $6.3 million.

The location and fair value of the Company's derivative instruments on the Consolidated Balance Sheets were as follows:

Asset Derivatives	Location on Consolidated Balance Sheets	**Fair Value at December 31, 2012**	Fair Value at December 31, 2011
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	**$18,084**	$27,687
	Other assets – noncurrent	**–**	2,768
		18,084	30,455
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	**220**	–
		220	–
Total asset derivatives		**$18,304**	$30,455

Liability Derivatives	Location on Consolidated Balance Sheets	**Fair Value at December 31, 2012**	Fair Value at December 31, 2011
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	**$ –**	$12,727
	Other liabilities – noncurrent	**–**	937
Interest rate derivatives	Other accrued liabilities	**6,255**	827
	Other liabilities – noncurrent	**–**	3,935
		6,255	18,426
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	**–**	437
		–	437
Total liability derivatives		**$6,255**	$18,863

Note 8 – Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance investment contract, to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $48.9 million and $38.4 million as of December 31, 2012 and 2011, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2012 and 2010, were $5.2 million and $5.8 million, respectively. The net unrealized loss on these investments for the year ended December 31, 2011, was $1.1 million. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The Company did not elect the fair value option, which records gains and losses in income, for its remaining available-for-sale securities, which include auction rate securities, mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as Investments on the Consolidated Balance Sheets. The Company's auction rate securities approximated cost and, as a result, there were no accumulated unrealized gains or losses recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets related to these investments. In the second quarter of 2012, the Company sold its auction rate securities at cost and did not realize any gains or losses. Unrealized gains or losses on mortgage-backed securities and U.S. Treasury securities are recorded in accumulated other comprehensive income (loss). Details of available-for-sale securities were as follows:

December 31, 2012	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Insurance investment contract	$37,250	$11,648	$ –	$48,898
Mortgage-backed securities	8,054	144	(3)	8,195
U.S. Treasury securities	1,763	43	–	1,806
Total	$47,067	$11,835	$(3)	$58,899

December 31, 2011	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Insurance investment contract	$31,884	$6,468	$ –	$38,352
Auction rate securities	11,400	–	–	11,400
Mortgage-backed securities	8,206	95	(5)	8,296
U.S. Treasury securities	1,619	37	–	1,656
Total	$53,109	$6,600	$(5)	$59,704

The fair value of the Company's money market funds approximates cost.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs.

The estimated fair values of the Company's assets and liabilities measured on a recurring basis are determined using the market approach.

The Company's Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer. The estimated fair value of the Company's Level 2 mortgage-backed securities and U.S. Treasury securities are based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources.

The estimated fair value of the Company's Level 2 insurance investment contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

The estimated fair value of the Company's Level 2 commodity derivative instruments is based upon futures prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties nonperformance risk is also evaluated.

The estimated fair value of the Company's Level 2 interest rate derivative instruments is measured using quoted market prices or pricing models using prevailing market interest rates as of the measurement date. Counterparty statements are utilized to determine the value of the interest rate derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The Company's and the counterparties nonperformance risk is evaluated.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2012 and 2011, there were no transfers between Levels 1 and 2.

The Company's assets and liabilities measured at fair value on a recurring basis are as follows:

	Fair Value Measurements at December 31, 2012, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2012
	(In thousands)			
Assets:				
Money market funds	$ –	$ 24,240	$ –	$ 24,240
Available-for-sale securities:				
Insurance investment contract*	–	48,898	–	48,898
Mortgage-backed securities	–	8,195	–	8,195
U.S. Treasury securities	–	1,806	–	1,806
Commodity derivative instruments	–	18,304	–	18,304
Total assets measured at fair value	$ –	$101,443	$ –	$101,443
Liabilities:				
Interest rate derivative instruments	$ –	$ 6,255	$ –	$ 6,255
Total liabilities measured at fair value	$ –	$ 6,255	$ –	$ 6,255

* The insurance investment contract invests approximately 28 percent in common stock of mid-cap companies, 28 percent in common stock of small-cap companies, 29 percent in common stock of large-cap companies and 15 percent in fixed-income and other investments.

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
	(In thousands)			
Assets:				
Money market funds	$ –	$ 97,500	$ –	$ 97,500
Available-for-sale securities:				
Insurance investment contract*	–	38,352	–	38,352
Auction rate securities	–	11,400	–	11,400
Mortgage-backed securities	–	8,296	–	8,296
U.S. Treasury securities	–	1,656	–	1,656
Commodity derivative instruments	–	30,455	–	30,455
Total assets measured at fair value	$ –	$187,659	$ –	$187,659
Liabilities:				
Commodity derivative instruments	$ –	$ 14,101	$ –	$ 14,101
Interest rate derivative instruments	–	4,762	–	4,762
Total liabilities measured at fair value	$ –	$ 18,863	$ –	$ 18,863

* The insurance investment contract invests approximately 33 percent in common stock of mid-cap companies, 34 percent in common stock of small-cap companies, 32 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only. The fair value was based on discounted future cash flows using current market interest rates. The estimated fair value of the Company's Level 2 long-term debt at December 31 was as follows:

	2012		2011	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$1,744,975**	**$1,888,135**	$1,424,678	$1,592,807

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities approximate their fair values.

Note 9 – Debt

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2012. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

The following table summarizes the outstanding credit facilities of the Company and its subsidiaries:

Company	Facility	Facility Limit	Amount Outstanding at December 31, 2012	Amount Outstanding at December 31, 2011	Letters of Credit at December 31, 2012	Expiration Date
				(In millions)		
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$125.0	$ 76.0 (b)	$ – (b)	$ –	10/4/17
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (c)	$ 2.0	$ –	$ –	12/27/13
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (d)	$ 26.2	$8.1	$ –	8/11/13
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (e)	$500.0	$217.0 (b)	$ – (b)	$20.2 (f)	6/8/17

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $125 million (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(d) Certain provisions allow for increased borrowings, up to a maximum of $80 million.
(e) The $500 million commercial paper program is supported by a revolving credit agreement with various banks totaling $500 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $650 million). There were no amounts outstanding under the credit agreement.
(f) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the preceding table.

Short-term borrowings

Cascade Natural Gas Corporation The weighted average interest rate for borrowings outstanding at December 31, 2012, was 3.3 percent.

Cascade's credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, Cascade will be in default under the credit agreement. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness.

Intermountain Gas Company The weighted average interest rate for borrowings outstanding at December 31, 2012, was 2.3 percent. These borrowings were classified as short-term borrowings because the revolving credit agreement expires within one year. The borrowings outstanding as of December 31, 2011, were classified as long-term debt as they were intended to be refinanced on a long-term basis through continued borrowings.

The credit agreement contains customary covenants and provisions, including covenants of Intermountain not to permit, as of the end of any fiscal quarter, the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

Intermountain's credit agreement contains cross-default provisions. These provisions state that if (A) Intermountain fails to make any payment with respect to any indebtedness or guarantee in excess of a specified amount, (B) any other event occurs that would permit the holders of indebtedness or the beneficiaries of guarantees to become payable, or (C) certain conditions result in an early termination date under any swap contract that is in excess of $10 million, then Intermountain shall be in default under the revolving credit agreement.

Long-term debt

MDU Resources Group, Inc. On October 4, 2012, the Company amended the revolving credit agreement to increase the borrowing limit to $125.0 million and extend the termination date to October 4, 2017. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

The credit agreement contains customary covenants and provisions, including covenants of the Company not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

There are no credit facilities that contain cross-default provisions between the Company and any of its subsidiaries.

MDU Energy Capital, LLC The ability to request additional borrowings under the master shelf agreement expired; however, there is debt outstanding that is reflected in the following table. The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (A) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (B) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent, or (C) the ratio of Intermountain's total debt (determined on a consolidated basis) to total capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of MDU Energy Capital earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter, to be greater than 1.5 to 1. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement).

MDU Energy Capital entered into a note purchase agreement on October 22, 2012, and issued $25.0 million of Senior Notes with due dates ranging from October 2022 to October 2042 at a weighted average interest rate of 4.1 percent. MDU Energy Capital contracted to issue an additional $25.0 million of Senior Notes under the agreement on May 15, 2013.

Centennial Energy Holdings, Inc. On June 8, 2012, Centennial entered into an amended and restated revolving credit agreement which replaced the previous revolving credit agreement and extended the termination date to June 8, 2017. Centennial's revolving credit agreement supports its commercial paper program. On June 28, 2012, Centennial increased its commercial paper borrowing limit to $500.0 million. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

Centennial's revolving credit agreement and certain debt outstanding under an expired uncommitted long-term master shelf agreement contain customary covenants and provisions, including a covenant of Centennial, not to permit, as of the end of any fiscal quarter, the ratio of total consolidated debt to total consolidated capitalization to be greater than 65 percent (for the revolving credit agreement) and a covenant of Centennial and certain of its subsidiaries, not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 60 percent (for the master shelf agreement). The master shelf agreement also includes a covenant that does not permit the ratio of Centennial's EBITDA to interest expense, for the 12-month period ended each fiscal quarter, to be less than 1.75 to 1. Other covenants include restrictions on the sale of certain assets, limitations on subsidiary indebtedness, minimum consolidated net worth, limitations on priority debt and the making of certain loans and investments.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements will be in default.

Centennial entered into a note purchase agreement on December 20, 2012, and issued $150.0 million of Senior Notes with due dates ranging from December 2019 to December 2027 at a weighted average interest rate of 4.6 percent. Centennial contracted to issue an additional $100.0 million of Senior Notes under the agreement on February 20, 2013.

On January 11, 2013, Centennial entered into a letter of credit agreement for the issuance of up to $29.0 million of letters of credit. This agreement will expire on January 11, 2015.

WBI Energy Transmission The ability to request additional borrowings under the uncommitted long-term private shelf agreement expired in 2011; however, there is debt outstanding that is reflected in the following table. The uncommitted long-term private shelf agreement contains customary covenants and provisions, including a covenant of WBI Energy Transmission not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include limitation on priority debt and some restrictions on the sale of certain assets and the making of certain investments.

Long-term Debt Outstanding Long-term debt outstanding at December 31 was as follows:

	2012	2011
	(In thousands)	
Senior Notes at a weighted average rate of 5.74%, due on dates ranging from January 17, 2013 to May 15, 2043	**$1,349,160**	$1,287,576
Commercial paper at a weighted average rate of .51%, supported by revolving credit agreements	**293,000**	–
Medium-Term Notes at a weighted average rate of 7.58%, due on dates ranging from February 4, 2013 to March 16, 2029	**59,000**	81,000
Other notes at a weighted average rate of 5.24%, due on dates ranging from September 1, 2020 to February 1, 2035	**40,090**	40,469
Credit agreements at a weighted average rate of 5.22%, due on dates ranging from November 27, 2013 to November 30, 2038	**3,768**	15,633
Discount	**(43)**	–
Total long-term debt	**1,744,975**	1,424,678
Less current maturities	**134,108**	139,267
Net long-term debt	**$1,610,867**	$1,285,411

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2012, aggregate $134.1 million in 2013; $9.3 million in 2014; $266.5 million in 2015; $288.5 million in 2016; $336.4 million in 2017 and $710.2 million thereafter.

Note 10 – Asset Retirement Obligations

The Company records obligations related to the plugging and abandonment of oil and natural gas wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations.

A reconciliation of the Company's liability, which is included in other accrued liabilities and other liabilities on the Consolidated Balance Sheets, for the years ended December 31 was as follows:

	2012	2011
	(In thousands)	
Balance at beginning of year	**$ 98,151**	$ 95,970
Liabilities incurred	**6,523**	3,870
Liabilities acquired	**–**	–
Liabilities settled	**(10,472)**	(10,418)
Accretion expense	**4,266**	4,466
Revisions in estimates	**3,655**	3,921
Other	**422**	342
Balance at end of year	**$102,545**	$ 98,151

The Company believes that any expenses related to asset retirement obligations at the Company's regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2012 and 2011, was $5.0 million and $5.7 million, respectively. The legally restricted assets consist primarily of money market funds and are reflected in other assets on the Consolidated Balance Sheets.

Note 11 – Preferred Stocks

Preferred stocks at December 31 were as follows:

	2012	2011
	(In thousands, except shares and per share amounts)	
Authorized:		
Preferred –		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A –		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference –		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
4.50% Series – 100,000 shares	**$10,000**	$10,000
4.70% Series – 50,000 shares	**5,000**	5,000
Total preferred stocks	**$15,000**	$15,000

For the years 2012, 2011 and 2010, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 per share and $102 per share, respectively.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The affirmative vote of two-thirds of a series of the Company's outstanding preferred stock is necessary for amendments to the Company's charter or bylaws that adversely affect that series; creation of or increase in the amount of authorized stock ranking senior to that series (or an affirmative majority vote where the authorization relates to a new class of stock that ranks on parity with such series); a voluntary liquidation or sale of substantially all of the Company's assets; a merger or consolidation, with certain exceptions; or the partial retirement of that series of preferred stock when all dividends on that series of preferred stock have not been paid. The consent of the holders of a particular series is not required for such corporate actions if the equivalent vote of all outstanding series of preferred stock voting together has consented to the given action and no particular series is affected differently than any other series.

Subject to the foregoing, the holders of common stock exclusively possess all voting power. However, if cumulative dividends on preferred stock are in arrears, in whole or in part, for one year, the holders of preferred stock would obtain the right to one vote per share until all dividends in arrears have been paid and current dividends have been declared and set aside.

Note 12 – Common Stock

The Stock Purchase Plan provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan is partially funded with the Company's common stock. From January 2010 through December 2012, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2012, there were 23.2 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. In addition, the Company and Centennial are generally restricted to paying dividends out of capital accounts or net assets. The most restrictive limitations are discussed below.

Pursuant to a covenant under a credit agreement, Centennial may only make distributions to the Company in an amount up to 100 percent of Centennial's consolidated net income after taxes, excluding noncash write-downs, for the immediately preceding fiscal year. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately $2.0 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2012. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $177 million of the Company's (excluding its subsidiaries) net assets, which represents common stockholders' equity including retained earnings, would be restricted from use for dividend payments at December 31, 2012. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 13 – Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and stock. As of December 31, 2012, there are 6.2 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy restricted stock, stock and performance share awards.

Total stock-based compensation expense was $4.0 million, net of income taxes of $2.5 million in 2012; $3.5 million, net of income taxes of $2.2 million in 2011; and $3.4 million, net of income taxes of $2.1 million in 2010.

As of December 31, 2012, total remaining unrecognized compensation expense related to stock-based compensation was approximately $5.6 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

Stock options

The Company had granted stock options to directors, key employees and employees. The Company has not granted stock options since 2003. Options granted to key employees automatically vested after nine years, but the plan provided for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expired ten years after the date of grant. Options granted to employees vested three years after the date of grant and expired ten years after the date of grant. Options granted to directors vested at the date of grant and expired ten years after the date of grant.

The fair value of each option outstanding was estimated on the date of grant using the Black-Scholes option-pricing model.

A summary of the status of the stock option plans at December 31, 2012, and changes during the year then ended was as follows:

	Number of Shares	Weighted Average Exercise Price
Balance at beginning of year	6,750	$13.03
Exercised	(6,750)	13.03
Balance at end of year	–	–

The Company received cash of $88,000, $5.7 million and $5.0 million from the exercise of stock options for the years ended December 31, 2012, 2011 and 2010, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2012, 2011 and 2010, was $60,000, $3.3 million and $2.6 million, respectively.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 53,888 shares with a fair value of $1.1 million, 55,141 shares with a fair value of $1.1 million and 43,128 shares with a fair value of $849,000 issued under this plan during the years ended December 31, 2012, 2011 and 2010, respectively.

A key employee of the Company received an award of 43,103 shares of common stock under a long-term incentive plan with a fair value of $930,000 during the year ended December 31, 2012.

Performance share awards

Since 2003, key employees of the Company have been awarded performance share awards each year. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group.

Target grants of performance shares outstanding at December 31, 2012, were as follows:

Grant Date	Performance Period	Target Grant of Shares
March 2010	2010-2012	213,432
February 2011	2011-2013	261,029
February 2012	2012-2014	311,675

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2012, 2011 and 2010 were:

	2012	2011	2010
Grant-date fair value	**$17.18**	$19.99	$17.40
Blended volatility range	**24.29% – 25.81%**	23.20% – 32.18%	25.69% – 35.36%
Risk-free interest rate range	**.10% – .35%**	.09% – 1.34%	.13% – 1.45%
Discounted dividends per share	**$ 1.19**	$ 1.23	$ 1.04

There were no performance shares that vested in 2012 or 2011. The fair value of performance share awards that vested during the year ended December 31, 2010, was $3.5 million.

A summary of the status of the performance share awards for the year ended December 31, 2012, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	762,154	$19.35
Granted	320,692	17.18
Vested	–	–
Forfeited	(296,710)	20.13
Nonvested at end of period	786,136	$18.17

Note 14 – Income Taxes

The components of income (loss) before income taxes from continuing operations for each of the years ended December 31 were as follows:

	2012	2011	2010
		(In thousands)	
United States	**$(47,175)**	$333,486	$336,450
Foreign	**1,708**	2,740	30,100
Income (loss) before income taxes from continuing operations	**$(45,467)**	$336,226	$366,550

Income tax expense (benefit) from continuing operations for the years ended December 31 was as follows:

	2012	2011	2010
		(In thousands)	
Current:			
Federal	**$(26,858)**	$ (7,188)	$ 37,014
State	**858**	778	10,589
Foreign	**(75)**	127	4,451
	(26,075)	(6,283)	52,054
Deferred:			
Income taxes:			
Federal	**(1,224)**	105,528	62,618
State	**(6,323)**	13,157	4,147
Investment tax credit – net	**44**	240	(180)
	(7,503)	118,925	66,585
Change in uncertain tax positions	**1,974**	(1,048)	3,230
Change in accrued interest	**458**	(1,320)	661
Total income tax expense (benefit)	**$(31,146)**	$110,274	$122,530

Components of deferred tax assets and deferred tax liabilities at December 31 were as follows:

	2012	2011
	(In thousands)	
Deferred tax assets:		
Regulatory matters	**$ 121,781**	$ 119,189
Accrued pension costs	**85,037**	95,260
Asset retirement obligations	**26,748**	26,380
Compensation-related	**23,441**	16,241
Legal and environmental contingencies	**8,046**	21,788
Other	**39,792**	41,055
Total deferred tax assets	**304,845**	319,913
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**755,392**	715,482
Basis differences on oil and natural gas producing properties	**167,113**	210,146
Regulatory matters	**82,077**	84,963
Intangible asset amortization	**14,078**	14,307
Other	**18,441**	23,774
Total deferred tax liabilities	**1,037,101**	1,048,672
Net deferred income tax liability	**$ (732,256)**	$ (728,759)

As of December 31, 2012 and 2011, no valuation allowance has been recorded associated with the previously identified deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2011, to December 31, 2012, to deferred income tax expense:

	2012
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 3,497**
Deferred taxes associated with other comprehensive loss	**1,267**
Deferred taxes associated with discontinued operations	**(9,863)**
Other	**(2,404)**
Deferred income tax expense for the period	**$(7,503)**

Total income tax expense (benefit) differs from the amount computed by applying the statutory federal income tax rate to income (loss) before taxes. The reasons for this difference were as follows:

Years ended December 31,	**2012**		2011		2010	
	Amount	%	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	**$(15,914)**	**35.0**	$117,679	35.0	$128,293	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit (expense)	**2,469**	**(5.4)**	10,653	3.2	10,210	2.8
Resolution of tax matters and uncertain tax positions	**2,559**	**(5.6)**	(3,906)	(1.2)	667	.2
Federal renewable energy credit	**(3,401)**	**7.5**	(3,485)	(1.0)	(2,185)	(.6)
Depletion allowance	**(3,728)**	**8.2**	(3,266)	(1.0)	(2,810)	(.8)
Deductible K-Plan dividends	**(2,829)**	**6.2**	(2,282)	(.7)	(2,309)	(.6)
Deferred tax rate changes	**(3,083)**	**6.8**	(417)	(.1)	(1,262)	(.3)
AFUDC equity	**(1,500)**	**3.3**	(873)	(.3)	(1,494)	(.4)
Other	**(5,719)**	**12.5**	(3,829)	(1.1)	(6,580)	(1.9)
Total income tax expense (benefit)	**$(31,146)**	**68.5**	$110,274	32.8	$122,530	33.4

The income tax benefit in 2012 resulted largely from the Company's write-downs of oil and natural gas properties, as discussed in Note 1.

Deferred income taxes have been accrued with respect to temporary differences related to the Company's foreign operations. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $7.7 million at December 31, 2012. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2012, was approximately $2.0 million.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years ending prior to 2007. The 2007 through 2009 tax years are currently under audit.

A reconciliation of the unrecognized tax benefits (excluding interest) for the years ended December 31 was as follows:

	2012	2011	2010
		(In thousands)	
Balance at beginning of year	**$11,206**	$ 9,378	$6,148
Additions for tax positions of prior years	**3,708**	4,172	3,230
Settlements	**–**	(2,344)	–
Balance at end of year	**$14,914**	$11,206	$9,378

Included in the balance of unrecognized tax benefits at December 31, 2012 and 2011, were $8.4 million and $6.6 million, respectively, of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $8.5 million, including approximately $2.0 million for the payment of interest and penalties at December 31, 2012, and was $6.0 million, including approximately $1.4 million for the payment of interest and penalties at December 31, 2011.

It is likely that substantially all of the unrecognized tax benefits, as well as interest, at December 31, 2012, will be settled in the next twelve months due to the anticipated settlement of federal and state audits.

For the years ended December 31, 2012, 2011 and 2010, the Company recognized approximately $740,000, $780,000 and $2.0 million, respectively, in interest expense. Penalties were not material in 2012, 2011 and 2010. The Company recognized interest income of approximately $290,000, $1.9 million and $20,000 for the years ended December 31, 2012, 2011 and 2010, respectively. The Company had accrued liabilities of approximately $1.4 million and $970,000 at December 31, 2012 and 2011, respectively, for the payment of interest.

Note 15 – Business Segment Data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The internal reporting of these operating segments is defined based on the reporting and review process used by the Company's chief executive officer and other management. The vast majority of the Company's operations are located within the United States. The Company also has an investment in a foreign country, which consists of Centennial Resources' equity method investment in ECTE.

The electric segment generates, transmits and distributes electricity in Montana, North Dakota, South Dakota and Wyoming. The natural gas distribution segment distributes natural gas in those states as well as in Idaho, Minnesota, Oregon and Washington. These operations also supply related value-added services.

The pipeline and energy services segment provides natural gas transportation, underground storage, processing and gathering services, as well as oil gathering, through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment also provides cathodic protection and other energy-related services.

The exploration and production segment is engaged in oil and natural gas acquisition, exploration, development and production activities in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico.

The construction materials and contracting segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated contracting services. This segment operates in the central, southern and western United States and Alaska and Hawaii.

The construction services segment specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes specialty equipment.

The Other category includes the activities of Centennial Capital, which insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer is to fund the deductible layers of the insured companies' general liability and automobile liability coverages. Centennial Capital also owns certain real and personal property. The Other category also includes Centennial Resources' equity method investment in ECTE.

The information below follows the same accounting policies as described in the Summary of Significant Accounting Policies. Information on the Company's businesses as of December 31 and for the years then ended was as follows:

	2012	2011	2010
		(In thousands)	
External operating revenues:			
Electric	**$ 236,895**	$ 225,468	$ 211,544
Natural gas distribution	**754,848**	907,400	892,708
Pipeline and energy services	**139,883**	210,846	254,776
	1,131,626	1,343,714	1,359,028
Exploration and production	**412,651**	359,873	318,570
Construction materials and contracting	**1,597,257**	1,509,538	1,445,148
Construction services	**932,013**	834,918	786,802
Other	**1,884**	2,449	147
	2,943,805	2,706,778	2,550,667
Total external operating revenues	**$4,075,431**	$4,050,492	$3,909,695
Intersegment operating revenues:			
Electric	**$ –**	$ –	$ –
Natural gas distribution	**–**	–	–
Pipeline and energy services	**53,274**	67,497	75,033
Exploration and production	**35,966**	93,713	115,784
Construction materials and contracting	**20,168**	472	–
Construction services	**6,545**	19,471	2,298
Other	**8,486**	8,997	7,580
Intersegment eliminations	**(124,439)**	(190,150)	(200,695)
Total intersegment operating revenues	**$ –**	$ –	$ –
Depreciation, depletion and amortization:			
Electric	**$ 32,509**	$ 32,177	$ 27,274
Natural gas distribution	**45,731**	44,641	43,044
Pipeline and energy services	**27,684**	25,502	26,001
Exploration and production	**160,681**	142,645	130,455
Construction materials and contracting	**79,527**	85,459	88,331
Construction services	**11,063**	11,399	12,147
Other	**2,010**	1,572	1,591
Total depreciation, depletion and amortization	**$ 359,205**	$ 343,395	$ 328,843

	2012	2011	2010
		(In thousands)	
Interest expense:			
Electric	**$ 12,421**	$ 13,745	$ 12,216
Natural gas distribution	**28,726**	29,444	28,996
Pipeline and energy services	**7,742**	10,516	9,064
Exploration and production	**9,018**	7,445	8,580
Construction materials and contracting	**15,211**	16,241	19,859
Construction services	**4,435**	4,473	4,411
Other	**13**	–	47
Intersegment eliminations	**(867)**	(510)	(162)
Total interest expense	**$ 76,699**	$ 81,354	$ 83,011
Income taxes:			
Electric	**$ 8,975**	$ 7,242	$ 11,187
Natural gas distribution	**12,005**	16,931	12,171
Pipeline and energy services	**15,291**	12,912	13,933
Exploration and production	**(108,264)**	46,298	49,034
Construction materials and contracting	**14,099**	11,227	13,822
Construction services	**24,128**	13,426	11,456
Other	**2,620**	2,238	10,927
Total income taxes	**$ (31,146)**	$ 110,274	$ 122,530
Earnings (loss) on common stock:			
Electric	**$ 30,634**	$ 29,258	$ 28,908
Natural gas distribution	**29,409**	38,398	36,944
Pipeline and energy services	**26,588**	23,082	23,208
Exploration and production	**(177,283)**	80,282	85,638
Construction materials and contracting	**32,420**	26,430	29,609
Construction services	**38,429**	21,627	17,982
Other	**4,797**	6,190	21,046
Earnings (loss) on common stock before income (loss) from discontinued operations	**(15,006)**	225,267	243,335
Income (loss) from discontinued operations, net of tax*	**13,567**	(12,926)	(3,361)
Total earnings (loss) on common stock	**$ (1,439)**	$ 212,341	$ 239,974
Capital expenditures:			
Electric	**$ 112,035**	$ 52,072	$ 85,787
Natural gas distribution	**130,178**	70,624	75,365
Pipeline and energy services	**133,787**	45,556	14,255
Exploration and production	**554,528**	272,855	355,845
Construction materials and contracting	**45,083**	52,303	25,724
Construction services	**14,835**	9,711	14,849
Other	**791**	18,759	2,182
Net proceeds from sale or disposition of property and other	**(57,460)**	(40,857)	(78,761)
Total net capital expenditures	**$ 933,777**	$ 481,023	$ 495,246
Assets:			
Electric**	**$ 760,324**	$ 672,940	$ 643,636
Natural gas distribution**	**1,703,459**	1,679,091	1,632,012
Pipeline and energy services	**622,470**	526,797	523,075
Exploration and production	**1,539,017**	1,481,556	1,342,808
Construction materials and contracting	**1,371,252**	1,374,026	1,382,836
Construction services	**429,547**	418,519	387,627
Other***	**256,422**	403,196	391,555
Total assets	**$6,682,491**	$6,556,125	$6,303,549

	2012	2011	2010
		(In thousands)	
Property, plant and equipment:			
Electric**	**$1,150,584**	$1,068,524	$1,027,034
Natural gas distribution**	**1,689,950**	1,568,866	1,508,845
Pipeline and energy services	**816,533**	719,291	683,807
Exploration and production	**2,764,560**	2,615,146	2,356,938
Construction materials and contracting	**1,504,981**	1,499,852	1,486,375
Construction services	**130,624**	124,796	122,940
Other	**50,519**	49,747	32,564
Less accumulated depreciation, depletion and amortization	**3,608,912**	3,361,208	3,103,323
Net property, plant and equipment	**$4,498,839**	$4,285,014	$4,115,180

* Reflected in the Other category.

** Includes allocations of common utility property.

*** Includes assets not directly assignable to a business (i.e. cash and cash equivalents, certain accounts receivable, certain investments and other miscellaneous current and deferred assets).

Note: The results reflect $391.8 million ($246.8 million after tax) of noncash write-downs of oil and natural gas properties in 2012.

Excluding the natural gas gathering arbitration charge of $16.5 million (after tax) in 2010, and the reversal of this arbitration charge of $15.0 million (after tax) in 2012, as discussed in Note 19, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from exploration and production, construction materials and contracting, construction services and other are all from nonregulated operations.

Capital expenditures for 2012, 2011 and 2010 include noncash transactions, including capital expenditure-related accounts payable. The net noncash transactions were $33.7 million in 2012, $24.0 million in 2011 and $17.5 million in 2010.

Note 16 – Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

Defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005, were discontinued. Employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. Effective January 1, 2010, all benefit and service accruals for nonunion and certain union plans were frozen. Effective June 30, 2011 and September 30, 2012, all benefit and service accruals for certain additional union employees were frozen. These employees will be eligible to receive additional defined contribution plan benefits.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at certain of the Company's businesses. Employees who attain age 55 with 10 years of continuous service by December 31, 2010, will be provided the current retiree medical insurance benefits or can elect the new benefit, if desired, regardless of when they retire. All other current employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire. These employees will be eligible for a specified company funded Retiree Reimbursement Account. Employees hired after December 31, 2009, will not be eligible for retiree medical benefits.

In 2012, the Company modified health care coverage for certain retirees. Effective January 1, 2013, post-65 coverage is replaced by a fixed-dollar subsidy for retirees and spouses to be used to purchase individual insurance through an exchange.

Changes in benefit obligation and plan assets for the years ended December 31, 2012 and 2011, and amounts recognized in the Consolidated Balance Sheets at December 31, 2012 and 2011, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	**2012**	2011
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 435,618**	$ 388,589	**$110,689**	$ 91,286
Service cost	**1,078**	2,252	**1,747**	1,443
Interest cost	**17,598**	19,500	**4,166**	4,700
Plan participants' contributions	**–**	–	**2,688**	2,644
Amendments	**–**	–	**(11,418)**	–
Actuarial loss	**30,939**	62,722	**3,469**	17,940
Curtailment gain	**–**	(13,939)	**–**	–
Benefits paid	**(26,122)**	(23,506)	**(7,983)**	(7,324)
Benefit obligation at end of year	**459,111**	435,618	**103,358**	110,689
Change in net plan assets:				
Fair value of plan assets at beginning of year	**278,000**	277,598	**68,085**	70,610
Actual gain (loss) on plan assets	**34,493**	(4,718)	**6,497**	(872)
Employer contribution	**22,813**	28,626	**5,074**	3,027
Plan participants' contributions	**–**	–	**2,688**	2,644
Benefits paid	**(26,122)**	(23,506)	**(7,983)**	(7,324)
Fair value of net plan assets at end of year	**309,184**	278,000	**74,361**	68,085
Funded status – under	**$(149,927)**	$(157,618)	**$ (28,997)**	$(42,604)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other accrued liabilities (current)	**$ –**	$ –	**$ (655)**	$ (550)
Other liabilities (noncurrent)	**(149,927)**	(157,618)	**(28,342)**	(42,054)
Net amount recognized	**$(149,927)**	$(157,618)	**$ (28,997)**	$(42,604)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	**$ 202,406**	$ 189,494	**$ 43,589**	$ 43,861
Prior service cost (credit)	**437**	(632)	**(18,594)**	(8,615)
Transition obligation	**–**	–	**–**	2,128
Total	**$ 202,843**	$ 188,862	**$ 24,995**	$ 37,374

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Accumulated other comprehensive (income) loss in the above table includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time. For more information on regulatory assets (liabilities) see Note 6.

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized on a straight-line basis over the expected average remaining service lives of active participants for non-frozen plans and over the average life expectancy of plan participants for frozen plans. The market-related value of assets is determined using a five-year average of assets. Unrecognized postretirement net transition obligation was amortized over a 20-year period ending 2012.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plans, of which all have accumulated benefit obligations in excess of plan assets, at December 31 were as follows:

	2012	2011
	(In thousands)	
Projected benefit obligation	**$459,111**	$435,618
Accumulated benefit obligation	**$459,111**	$435,618
Fair value of plan assets	**$309,184**	$278,000

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31 were as follows:

	Pension Benefits			Other Postretirement Benefits		
	2012	2011	2010	**2012**	2011	2010
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	**$ 1,078**	$ 2,252	$ 2,889	**$ 1,747**	$ 1,443	$ 1,357
Interest cost	**17,598**	19,500	19,761	**4,166**	4,700	4,817
Expected return on assets	**(23,536)**	(22,809)	(23,643)	**(4,890)**	(5,051)	(5,512)
Amortization of prior service cost (credit)	**(46)**	45	152	**(1,438)**	(2,677)	(3,303)
Recognized net actuarial loss	**7,070**	4,656	2,622	**2,134**	753	845
Curtailment loss (gain)	**(1,023)**	1,218	–	**–**	–	–
Amortization of net transition obligation	**–**	–	–	**2,128**	2,125	2,125
Net periodic benefit cost, including amount capitalized	**1,141**	4,862	1,781	**3,847**	1,293	329
Less amount capitalized	**937**	1,196	791	**910**	(50)	(92)
Net periodic benefit cost	**204**	3,666	990	**2,937**	1,343	421
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net loss	**19,982**	76,310	20,477	**1,863**	23,863	1,462
Prior service cost (credit)	**–**	–	353	**(11,418)**	–	121
Amortization of actuarial loss	**(7,070)**	(4,656)	(2,622)	**(2,134)**	(753)	(845)
Amortization of prior service (cost) credit	**1,069**	(1,263)	(152)	**1,438**	2,677	3,303
Amortization of net transition obligation	**–**	–	–	**(2,128)**	(2,125)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	**13,981**	70,391	18,056	**(12,379)**	23,662	1,916
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	**$ 14,185**	$ 74,057	$ 19,046	**$ (9,442)**	$25,005	$ 2,337

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2013 are $7.1 million and $71,000, respectively. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2013 are $2.6 million and $1.5 million, respectively.

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	**2012**	2011
Discount rate	**3.65%**	4.16%	**3.67%**	4.13%
Expected return on plan assets	**7.00%**	7.75%	**6.00%**	6.75%
Rate of compensation increase	**N/A**	N/A	**4.00%**	4.00%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	**2012**	2011
Discount rate	**4.16%**	5.26%	**4.13%**	5.21%
Expected return on plan assets	**7.75%**	7.75%	**6.75%**	6.75%
Rate of compensation increase	**N/A***	4.00% / N/A*	**4.00%**	4.00%

* Effective June 30, 2011 and September 30, 2012, all benefit and service accruals for a union plan were frozen. Compensation increases had previously been frozen for all other plans.

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The expected rate of return on pension plan assets is based on the targeted asset allocation range of 60 percent to 70 percent equity securities and 30 percent to 40 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 65 percent to 75 percent equity securities and 25 percent to 35 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2012	2011
Health care trend rate assumed for next year	**6.0% – 8.0%**	6.0% – 8.0%
Health care cost trend rate – ultimate	**5.0% – 6.0%**	5.0% – 6.0%
Year in which ultimate trend rate achieved	**2017**	2017

The Company's other postretirement benefit plans include health care and life insurance benefits for certain retirees. The plans underlying these benefits may require contributions by the retiree depending on such retiree's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over six percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2012:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 340	$ (278)
Effect on postretirement benefit obligation	$5,724	$(4,858)

The Company's pension assets are managed by 14 outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs.

The estimated fair values of the Company's pension plan assets are determined using the market approach.

The carrying value of the pension plans' Level 1 and Level 2 cash equivalents approximates fair value and is determined using observable inputs in active markets or the net asset value of shares held at year end, which is determined using other observable inputs including pricing from outside sources. Units of this fund can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in high quality, short-term instruments of domestic and foreign issuers.

The estimated fair value of the pension plans' Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded.

The estimated fair value of the pension plans' Level 1 and Level 2 collective and mutual funds are based on the net asset value of shares held at year end, based on either published market quotations on active markets or other known sources including pricing from outside sources.

The estimated fair value of the pension plans' Level 2 corporate and municipal bonds is determined using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, future cash flows and other reference data.

The estimated fair value of the pension plans' Level 1 U.S. Treasury securities are valued based on quoted prices on an active market.

The estimated fair value of the pension plans' Level 2 U.S. Treasury and mortgage-backed securities are valued mainly using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, to be announced prices, future cash flows and other reference data. Some of these securities are valued using pricing from outside sources.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2012 and 2011, there were no transfers between Levels 1 and 2.

The fair value of the Company's pension net plan assets by class is as follows:

	Fair Value Measurements at December 31, 2012, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2012
	(In thousands)			
Assets:				
Cash equivalents	$ 2,145	$10,460	$ –	$ 12,605
Equity securities:				
U.S. companies	86,981	–	–	86,981
International companies	39,818	–	–	39,818
Collective and mutual funds*	82,787	20,065	–	102,852
Corporate bonds	–	45,112	–	45,112
Municipal bonds	–	9,302	–	9,302
U.S. Treasury securities	7,980	4,534	–	12,514
Total assets measured at fair value	$219,711	$89,473	$ –	$309,184

* Collective and mutual funds invest approximately 12 percent in common stock of mid-cap U.S. companies, 26 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 41 percent in corporate bonds and 8 percent in other investments.

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
	(In thousands)			
Assets:				
Cash equivalents	$ 2,256	$17,534	$ –	$ 19,790
Equity securities:				
U.S. companies	99,315	–	–	99,315
International companies	35,353	–	–	35,353
Collective and mutual funds*	43,214	15,541	–	58,755
Corporate bonds	–	23,579	289	23,868
Mortgage-backed securities	–	22,987	–	22,987
Municipal bonds	–	9,290	–	9,290
U.S. Treasury securities	–	8,642	–	8,642
Total assets measured at fair value	$180,138	$97,573	$289	$278,000

* Collective and mutual funds invest approximately 26 percent in common stock of mid-cap U.S. companies, 26 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 6 percent in corporate bonds and 29 percent in other investments.

The following table sets forth a summary of changes in the fair value of the pension plans' Level 3 assets for the year ended December 31, 2012:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)
	Corporate Bonds
	(In thousands)
Balance at beginning of year	$ 289
Total realized/unrealized losses	(47)
Purchases, issuances and settlements (net)	(242)
Balance at end of year	$ –

The following table sets forth a summary of changes in the fair value of the pension plans' Level 3 assets for the year ended December 31, 2011:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Corporate Bonds	Collateral Held on Loaned Securities	Total
		(In thousands)	
Balance at beginning of year	$ –	$ 694	$ 694
Total realized/unrealized losses	(2)	(259)	(261)
Purchases, issuances and settlements (net)	291	(435)	(144)
Balance at end of year	$289	$ –	$ 289

The estimated fair values of the Company's other postretirement benefit plan assets are determined using the market approach.

The estimated fair value of the other postretirement benefit plan's Level 1 and Level 2 cash equivalents is valued at the net asset value of shares held at year end, based on published market quotations on active markets, or using other known sources including pricing from outside sources. Units of this fund can be redeemed on a daily basis at their net asset value and have no redemption restrictions. The assets are invested in high-quality, short-term money market instruments that consist of municipal obligations.

The estimated fair value of the other postretirement benefit plan's Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded.

The estimated fair value of the other postretirement benefit plan's Level 2 insurance investment contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2012 and 2011, there were no transfers between Levels 1 and 2.

The fair value of the Company's other postretirement benefit plan assets by asset class is as follows:

	Fair Value Measurements at December 31, 2012, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2012
	(In thousands)			
Assets:				
Cash equivalents	$1,053	$ 1,991	$ –	$ 3,044
Equity securities:				
U.S. companies	2,207	–	–	2,207
International companies	260	–	–	260
Insurance investment contract*	–	68,850	–	68,850
Total assets measured at fair value	$3,520	$70,841	$ –	$74,361

* The insurance investment contract invests approximately 51 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 10 percent in mortgage-backed securities, 11 percent in corporate bonds and 13 percent in other investments.

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
	(In thousands)			
Assets:				
Cash equivalents	$ 59	$ 1,836	$ –	$ 1,895
Equity securities:				
U.S. companies	2,098	–	–	2,098
International companies	262	–	–	262
Insurance investment contract*	–	63,830	–	63,830
Total assets measured at fair value	$2,419	$65,666	$ –	$68,085

* The insurance investment contract invests approximately 49 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 12 percent in mortgage-backed securities, 11 percent in corporate bonds and 13 percent in other investments.

The Company expects to contribute approximately $18.1 million to its defined benefit pension plans and approximately $2.3 million to its postretirement benefit plans in 2013.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
	(In thousands)		
2013	$ 23,193	$ 6,099	$256
2014	23,386	6,134	248
2015	23,646	6,127	239
2016	23,954	6,082	228
2017	24,531	6,083	217
2018 – 2022	128,971	29,051	896

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company had investments of $84.4 million and $76.9 million at December 31, 2012 and 2011, respectively, consisting of equity securities of $41.9 million and $38.4 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $32.7 million and $31.8 million, respectively, and other investments of $9.8 million and $6.7 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was $8.1 million, $8.1 million and $7.8 million in 2012, 2011 and 2010, respectively. The total projected benefit obligation for these plans was $113.0 million and $113.8 million at December 31, 2012 and 2011, respectively. The accumulated benefit obligation for these plans was $107.5 million and $105.7 million at December 31, 2012 and 2011, respectively. A weighted average discount rate of 3.44 percent and 4.00 percent at December 31, 2012 and 2011, respectively, and a rate of compensation increase of 3.00 percent and 4.00 percent at December 31, 2012 and 2011, were used to determine benefit obligations. A discount rate of 4.00 percent and 5.11 percent at December 31, 2012 and 2011, respectively, and a rate of compensation increase of 4.00 percent and 4.00 percent at December 31, 2012 and 2011, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $5.7 million in 2013; $5.6 million in 2014; $6.7 million in 2015; $6.5 million in 2016; $6.7 million in 2017 and $37.3 million for the years 2018 through 2022.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Costs incurred under this plan for 2012 were $84,000.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees and the costs incurred under these plans were $29.3 million in 2012, $27.1 million in 2011 and $24.4 million in 2010.

Multiemployer plans

The Company contributes to a number of multiemployer defined benefit pension plans under the terms of collective-bargaining agreements that cover its union-represented employees. The risks of participating in these multiemployer plans are different from single-employer plans in the following aspects:

- Assets contributed to the multiemployer plan by one employer may be used to provide benefits to employees of other participating employers
- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers
- If the Company chooses to stop participating in some of its multiemployer plans, the Company may be required to pay those plans an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in these plans is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2012 and 2011 is for the plan's year-end at December 31, 2011, and December 31, 2010, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded.

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status 2012	Pension Protection Act Zone Status 2011	FIP/RP Status Pending/ Implemented	Contributions 2012	Contributions 2011	Contributions 2010	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Edison Pension Plan	93-6061681-001	Green as of 12/31/2012	Green as of 12/31/2011	No	**$ 5,171**	$ 2,700	$ 1,933	No	12/31/2014
IBEW Local 38 Pension Plan	34-6574238-001	Yellow as of 4/30/2012	Yellow as of 4/30/2011	Implemented	**2,771**	1,469	1,277	No	4/27/2014
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2012	Red as of 6/30/2011	Implemented	**1,093**	1,331	1,569	No	12/1/2013
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/29/2012	Red as of 2/28/2011	Implemented	**564**	722	781	No	8/31/2015
Laborers Pension Trust Fund for Northern California	94-6277608-001	Yellow as of 5/31/2012	Yellow as of 5/31/2011	Implemented	**567**	628	413	No	6/30/2011*–6/30/2012*
Local Union 212 IBEW Pension Trust Fund	31-6127280-001	Yellow as of 4/30/2012	Yellow as of 4/30/2011	Implemented	**664**	776	679	No	6/2/2013
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**5,603**	4,841	4,826	No	8/31/2011*–12/31/2016
OE Pension Trust Fund	94-6090764-001	Yellow as of 12/31/2012	Yellow as of 12/31/2011	Implemented	**1,156**	1,367	1,035	No	6/30/2010*–3/31/2016
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming	83-6011320-001	Red as of 12/31/2012	Red as of 12/31/2011	Implemented	**91**	96	106	No	10/31/2005*
Operating Engineers Pension Trust	95-6032478-001	Red as of 6/30/2012	Red as of 6/30/2011	Implemented	**761**	458	343	No	6/30/2013–12/31/2016
Other funds					**16,338**	14,770	17,314		
Total contributions					**$34,779**	$29,158	$30,276		

* Plan includes collective bargaining agreements which have expired. The agreements contain provisions that automatically renew the existing contracts in lieu of a new negotiated collective bargaining agreement.

The Company was listed in the plans' Forms 5500 as providing more than 5 percent of the total contributions for the following plans and plan years:

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Defined Benefit Pension Plan of AGC-IUOE Local 701 Pension Trust Fund	2010
Edison Pension Plan	2011 and 2010
Eighth District Electrical Pension Fund	2010
IBEW Local 38 Pension Plan	2011 and 2010
IBEW Local No. 82 Pension Plan	2011 and 2010
Local Union No. 124 IBEW Pension Trust Fund	2011 and 2010
Local Union 212 IBEW Pension Trust Fund	2011 and 2010
IBEW Local Union No. 357 Pension Plan A	2011 and 2010
IBEW Local 648 Pension Plan	2011 and 2010
Idaho Plumbers and Pipefitters Pension Plan	2011 and 2010
Minnesota Teamsters Construction Division Pension Fund	2011 and 2010
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming	2011 and 2010
Plumbers and Pipefitters Local 162 Pension Fund	2010
Pension and Retirement Plan of Plumbers and Pipefitters Union Local No. 525	2011

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The Company also contributes to a number of multiemployer other postretirement plans under the terms of collective-bargaining agreements that cover its union-represented employees. These plans provide benefits such as health insurance, disability insurance and life insurance to retired union employees. Many of the multiemployer other postretirement plans are combined with active multiemployer health and welfare plans. The Company's total contributions to its multiemployer other postretirement plans, which also includes contributions to active multiemployer health and welfare plans, were $31.4 million, $24.0 million and $24.7 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Amounts contributed in 2012, 2011 and 2010 to defined contribution multiemployer plans were $18.7 million, $15.3 million and $15.4 million, respectively.

Note 17 – Jointly Owned Facilities

The consolidated financial statements include the Company's 22.7 percent, 25.0 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station, Coyote Station and Wygen III, respectively. Each owner of the stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the stations operating expenses was reflected in the appropriate categories of operating expenses (fuel, operation and maintenance, and taxes, other than income) in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2012	2011
	(In thousands)	
Big Stone Station:		
Utility plant in service	**$ 63,146**	$ 63,715
Less accumulated depreciation	**40,859**	42,475
	$ 22,287	$ 21,240
Coyote Station:		
Utility plant in service	**$135,073**	$131,719
Less accumulated depreciation	**87,524**	86,788
	$ 47,549	$ 44,931
Wygen III:		
Utility plant in service	**$ 63,462**	$ 63,300
Less accumulated depreciation	**3,368**	2,106
	$ 60,094	$ 61,194

Note 18 – Regulatory Matters and Revenues Subject to Refund

On September 26, 2012, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase. Montana-Dakota requested a total increase of $3.5 million annually or approximately 5.9 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities, the landfill gas production facility, a region operations building, automated meter reading and a new customer billing system. Montana-Dakota requested an interim increase, subject to refund, of $1.7 million or approximately 2.9 percent. A hearing has been scheduled for May 1, 2013.

On December 21, 2012, Montana-Dakota filed an application with the SDPUC for a natural gas rate increase. Montana-Dakota requested a total increase of $1.5 million annually or approximately 3.3 percent above current rates. The requested increase includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities, the landfill gas production facility, an operations building, automated meter reading and a new customer billing system.

Note 19 – Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, where feasible, an estimate of the possible loss. The Company had accrued liabilities of $22.5 million and $64.1 million for contingencies related to litigation and environmental matters as of December 31, 2012 and 2011, respectively, which includes amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Guarantee Obligation Under a Construction Contract Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent. In February 2009, Centennial received a Notice and Demand from LPP under the guarantee agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. In December 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association seeking compensatory damages of $149.7 million. An arbitration award was issued January 13, 2012, awarding LPP $22.0 million. Centennial subsequently received a demand from LPP for payment of the arbitration award plus interest and attorneys' fees. An accrual related to the guarantee as a result of the arbitration award was recorded in discontinued operations on the Consolidated Statement of Income in the fourth quarter of 2011. CEM filed a petition with the New York Supreme Court to vacate the arbitration award in favor of LPP. On October 19, 2012, Centennial moved to intervene in the New York Supreme Court action to vacate the arbitration award and also filed a complaint with the New York Supreme Court seeking a declaration that LPP is not entitled to indemnification from Centennial under the guaranty for the arbitration award. On November 20, 2012, the New York Supreme Court granted CEM's petition to vacate the arbitration award. Due to the vacation of the arbitration award, the Company no longer believes the loss related to this matter to be probable and thus the liability that was previously recorded in 2011 was reversed in the fourth quarter of 2012. The effect of this was recorded in discontinued operations on the Consolidated Statement of Income. Centennial anticipates LPP will appeal the decision upon entry of a written order. We believe that it is reasonably possible that a loss related to this matter could result if LPP is successful in its appeal, the arbitration award is affirmed and LPP continues to assert its demand against Centennial under the guarantee for payment of the arbitration award, attorney's fees and interest. For more information regarding discontinued operations, see Note 3.

Construction Materials Until the fall of 2011 when it discontinued active mining operations at the pit, JTL operated the Target Range Gravel Pit in Missoula County, Montana under a 1975 reclamation contract pursuant to the Montana Opencut Mining Act. In September 2009, the Montana DEQ sent a letter asserting JTL was in violation of the Montana Opencut Mining Act by conducting mining operations outside a permitted area. JTL filed a complaint in Montana First Judicial District Court in June 2010, seeking a declaratory order that the reclamation contract is a valid permit under the Montana Opencut Mining Act. The Montana DEQ filed an answer and counterclaim to the complaint in August 2011, alleging JTL was in violation of the Montana Opencut Mining Act and requesting imposition of penalties of not more than $3.7 million plus not more than $5,000 per day from the date of the counterclaim. The Company believes the operation of the Target Range Gravel Pit was conducted under a valid permit; however, the imposition of civil penalties is reasonably possible. The Company filed an application for amendment of its opencut mining permit and intends to resolve this matter through settlement or continuation of the Montana First Judicial District Court litigation.

Natural Gas Gathering Operations In January 2010, SourceGas filed an application with the Colorado State District Court to compel WBI Energy Midstream to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of WBI Energy Midstream's pipeline gathering systems in Montana. WBI Energy Midstream resisted the application and sought a declaratory order interpreting the gathering contract. In May 2010, the Colorado State District Court granted the application and ordered WBI Energy Midstream into arbitration. An arbitration hearing was held in August 2010. In October 2010, the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. As a result, WBI Energy Midstream, which is included in the pipeline and energy services segment, recorded a $26.6 million charge ($16.5 million after tax) in the third quarter of 2010, which is recorded in operation and maintenance expense on the Consolidated Statement of Income. On April 20, 2011, the Colorado State District Court confirmed the arbitration award as a court judgment. WBI Energy Midstream filed an appeal from the Colorado State District Court's order and judgment to the Colorado Court of Appeals. The Colorado Court of Appeals issued a decision on May 24, 2012, reversing the Colorado State District Court order compelling arbitration, vacating the final award and remanding the case to the Colorado State District Court to determine SourceGas's claims and WBI Energy Midstream's counterclaims. As a result of the Colorado Court of Appeals decision, in the second quarter of 2012, WBI Energy Midstream changed its estimated loss related to this matter. This resulted in a reduction of expense of $24.1 million ($15.0 million after tax), which is largely reflected in operation and maintenance expense on the Consolidated Statement of Income. On August 2, 2012, SourceGas filed a petition for writ of certiorari with the Colorado Supreme Court for review of the Colorado Court of Appeals decision. WBI Energy Midstream anticipates that if the Colorado Supreme Court were to grant a writ of certiorari and remand the matter to the Colorado State District Court, SourceGas will assert claims similar to those asserted in the arbitration proceeding.

In a related matter, Omimex filed a complaint against WBI Energy Midstream in Montana Seventeenth Judicial District Court in July 2010 alleging WBI Energy Midstream breached a separate gathering contract with Omimex as a result of the increased operating pressures demanded by SourceGas on the same natural gas gathering system. In December 2011, Omimex filed an amended complaint alleging WBI Energy Midstream breached obligations to operate its gathering system as a common carrier under United States and Montana law. WBI Energy Midstream removed the action to the United States District Court for the District of Montana. Expert reports submitted by Omimex contended its damages as a result of the increased operating pressures were $16.1 million to $22.6 million, however, the experts have since revised their calculation of Omimex's damages to $4.8 million. The Company believes the claims asserted by Omimex are without merit and an award is not deemed probable. The Company intends to vigorously defend against the claims. A trial on the matter is scheduled for May 2013.

The Company also is involved in other legal actions in the ordinary course of its business. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above and other legal proceedings will not have a material effect upon the Company's financial position, results of operations or cash flows.

Environmental matters

Portland Harbor Site In December 2000, Knife River – Northwest was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by Knife River – Northwest from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include Knife River – Northwest or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $70 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study have been completed, the EPA has decided on a strategy and a ROD has been published. Corrective action will be taken after the development of a proposed plan and ROD on the harbor site is issued. Knife River – Northwest also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Portland Harbor Natural Resource Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, Knife River – Northwest does not believe it is a Responsible Party. In addition, Knife River – Northwest has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for liabilities incurred in relation to the above matters pursuant to the terms of their sale agreement. Knife River – Northwest has entered into an agreement tolling the statute of limitations in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study. By letter in March 2009, LWG stated its intent to file suit against Knife River – Northwest and others to recover LWG's investigation costs to the extent Knife River – Northwest cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, Knife River – Northwest has agreed to participate in the alternative dispute resolution process.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above referenced administrative action.

Manufactured Gas Plant Sites There are three claims against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors.

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. The Oregon DEQ is preparing a staff report which will recommend a cleanup alternative for the site. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has accrued $1.3 million for remediation of this site.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In May 2012, the EPA added the site to the National Priorities List. Cascade is in discussions with the EPA regarding an administrative settlement agreement and consent order with the intent of reaching consensus on the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $6.7 million for the remedial investigation and feasibility study and $6.4 million for remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

The third claim is for contamination at a site in Bellingham, Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade and its predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. Other PRPs have reached an agreed order and work plan with the Washington Department of Ecology for completion of a remedial investigation and feasibility study for the site. A report documenting the initial phase of the remedial investigation was completed in June 2011. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim although Cascade believes its proportional share of any liability will be relatively small in comparison to other PRPs. The plant manufactured gas from coal between approximately 1890 and 1946. In 1946, shortly after Cascade's predecessor acquired the plant, it converted the plant to a propane-air gas facility. There are no documented wastes or by-products resulting from the mixing or distribution of propane-air gas.

Cascade has received notices from certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers. The accruals related to these matters are reflected in regulatory assets. For more information, see Note 6.

Halawa Quarry The State of Hawaii Department of Health issued a Notice of Violation to Hawaiian Cement dated August 31, 2012, alleging violations of Hawaii's Water Pollution statute at Hawaiian Cement's Halawa Quarry by failure to comply with the quarry's National Pollutant Discharge Elimination System permit by failing to design, construct and maintain a facility to contain or treat the volume of all process wastewater and storm water that would result from a 10-year, 24-hour rainfall event. The Notice of Violation also alleges Hawaiian Cement violated the quarry's permit by discharging pollution, including levels of pH and total suspended solids in excess of the permit limits, on three occasions in January, June and December 2011. The Notice of Violation seeks development and implementation of corrective action plans and unspecified administrative penalties. Hawaiian Cement expects to resolve the Notice of Violation through a negotiated settlement with monetary penalties of approximately $100,000 as well as development and implementation of corrective action plans, the final cost of which has not been determined but which are not expected to be material.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2012, were $32.2 million in 2013, $22.5 million in 2014, $13.1 million in 2015, $9.1 million in 2016, $5.1 million in 2017 and $36.0 million thereafter. Rent expense was $42.9 million, $40.7 million and $38.7 million for the years ended December 31, 2012, 2011 and 2010, respectively.

Purchase commitments

The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation and storage, service and construction materials supply contracts. These commitments range from one to 48 years. The commitments under these contracts as of December 31, 2012, were $494.9 million in 2013, $261.4 million in 2014, $150.4 million in 2015, $92.3 million in 2016, $70.0 million in 2017 and $857.5 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2012, 2011 and 2010, were $718.4 million, $626.3 million and $611.7 million.

Guarantees

Centennial guaranteed CEM's obligations under a construction contract. For more information, see Litigation in this note.

In connection with the sale of the Brazilian Transmission Lines, as discussed in Note 4, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines.

WBI Holdings has guaranteed certain of Fidelity's oil and natural gas swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the oil and natural gas swap and collar agreements as the amount of the obligation is dependent upon oil and natural gas commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the oil and natural gas swap and collar agreements at December 31, 2012, expire in the year 2013; however, Fidelity continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. There were no amounts outstanding by Fidelity at December 31, 2012. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts and certain other guarantees. At December 31, 2012, the fixed maximum amounts guaranteed under these agreements aggregated $59.7 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $38.7 million in 2013; $2.2 million in 2014; $300,000 in 2015; $100,000 in 2016; $600,000 in 2018; $300,000 in 2019; $13.5 million, which is subject to expiration on a specified number of days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $600,000 and was reflected on the Consolidated Balance Sheet at December 31, 2012. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2012, the fixed maximum amounts guaranteed under these letters of credit, aggregated $25.0 million and are scheduled to expire in 2013. There were no amounts outstanding under the above letters of credit at December 31, 2012.

WBI Holdings has an outstanding guarantee to WBI Energy Transmission. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At December 31, 2012, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2014. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $900,000. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at December 31, 2012, because this intercompany transaction was eliminated in consolidation.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2012.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries, as well as an arbitration award. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2012, approximately $488 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Variable interest entities

Fuel Contract On October 10, 2012, the Coyote Station entered into a new coal supply agreement with Coyote Creek that will replace a coal supply agreement that expires in May 2016. The new agreement provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station, of which the Company is a 25.0 percent owner, for the period May 2016 through December 2040.

The new coal supply agreement creates a variable interest in Coyote Creek due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal will cover all costs of operations as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of Coyote Creek as they would be required to buy the assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of Coyote Creek in that they are required to buy the entity at the end of the contract term at equity value. The Company has determined that Coyote Creek is a variable interest entity. However, the Company has concluded that it is not the primary beneficiary of Coyote Creek because power to direct the activities of the entity are considered to be shared by the four unrelated owners of the Coyote Station, with no primary beneficiary existing. As a result, Coyote Creek is not required to be consolidated in the Company's financial statements.

At December 31, 2012, Coyote Creek was not yet operational. The assets and liabilities of Coyote Creek and exposure to loss as a result of the Company's involvement with the variable interest entity at December 31, 2012, is not material.

Note 20 – Subsequent Event

On February 7, 2013, the Company formed a joint venture with Calumet Specialty Products Partners, L.P. to develop, build and operate a diesel topping plant in southwestern North Dakota. The joint venture will be called Dakota Prairie Refining, LLC. The Company's participation in the joint venture will be through its wholly owned subsidiary, WBI Energy, Inc.

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2012 and 2011:

	First Quarter	Second Quarter*	Third Quarter**	Fourth Quarter***
	(In thousands, except per share amounts)			
2012				
Operating revenues	**$852,807**	**$967,962**	**$1,173,518**	**$1,081,144**
Operating expenses	**781,750**	**876,248**	**1,207,553**	**1,190,673**
Operating income (loss)	**71,057**	**91,714**	**(34,035)**	**(109,529)**
Income (loss) from continuing operations	**35,890**	**49,007**	**(29,532)**	**(69,686)**
Income (loss) from discontinued operations, net of tax	**(100)**	**5,106**	**(139)**	**8,700**
Net income (loss)	**35,790**	**54,113**	**(29,671)**	**(60,986)**
Earnings (loss) per common share – basic:				
Earnings (loss) before discontinued operations	**.19**	**.26**	**(.16)**	**(.37)**
Discontinued operations, net of tax	**–**	**.03**	**–**	**.05**
Earnings (loss) per common share – basic	**.19**	**.29**	**(.16)**	**(.32)**
Earnings (loss) per common share – diluted:				
Earnings (loss) before discontinued operations	**.19**	**.26**	**(.16)**	**(.37)**
Discontinued operations, net of tax	**–**	**.03**	**–**	**.05**
Earnings (loss) per common share – diluted	**.19**	**.29**	**(.16)**	**(.32)**
Weighted average common shares outstanding:				
Basic	**188,811**	**188,831**	**188,831**	**188,831**
Diluted	**189,182**	**189,107**	**188,831**	**188,831**
2011				
Operating revenues	$901,805	$930,757	$1,152,181	$1,065,749
Operating expenses	823,739	848,454	1,032,760	939,172
Operating income	78,066	82,303	119,421	126,577
Income from continuing operations	42,529	45,235	64,100	74,088
Income (loss) from discontinued operations, net of tax	448	(168)	(126)	(13,080)
Net income	42,977	45,067	63,974	61,008
Earnings per common share – basic:				
Earnings before discontinued operations	.22	.24	.34	.39
Discontinued operations, net of tax	.01	–	–	(.07)
Earnings per common share – basic	.23	.24	.34	.32
Earnings per common share – diluted:				
Earnings before discontinued operations	.22	.24	.34	.39
Discontinued operations, net of tax	.01	–	–	(.07)
Earnings per common share – diluted	.23	.24	.34	.32
Weighted average common shares outstanding:				
Basic	188,671	188,794	188,794	188,794
Diluted	188,815	188,968	188,797	188,932

* 2012 reflects a net benefit of $15.0 million (after tax) related to natural gas gathering operations litigation and a net benefit largely related to estimated insurance recoveries related to the guarantee of a construction contract. For more information, see Note 19.

** 2012 reflects a $100.9 million after-tax noncash write-down of oil and natural gas properties. For more information, see Note 1.

*** 2012 reflects a $145.9 million after-tax noncash write-down of oil and natural gas properties and the reversal of an arbitration charge of $13.0 million (after tax) related to a guarantee of a construction contract, which was partially offset by the reversal of estimated insurance recoveries, as previously discussed. 2011 reflects an arbitration charge of $13.0 million (after tax) related to a guarantee of a construction contract. For more information, see Notes 1 and 19, respectively.

FORM 10-K

Certain Company operations are highly seasonal and revenues from and certain expenses for such operations may fluctuate significantly among quarterly periods. Accordingly, quarterly financial information may not be indicative of results for a full year.

Exploration and Production Activities (Unaudited)

Fidelity is involved in the acquisition, exploration, development and production of oil and natural gas resources. Fidelity shares revenues and expenses from the development of specified properties in the Rocky Mountain and Mid-Continent/Gulf States regions of the United States in proportion to its ownership interests.

The information that follows includes Fidelity's proportionate share of all its oil and natural gas interests.

The following table sets forth capitalized costs and accumulated depreciation, depletion and amortization related to oil and natural gas producing activities at December 31:

	2012	2011	2010
		(In thousands)	
Subject to amortization	**$2,531,562**	$2,345,114	$2,138,565
Not subject to amortization	**191,794**	232,462	182,402
Total capitalized costs	**2,723,356**	2,577,576	2,320,967
Less accumulated depreciation, depletion and amortization	**1,383,386**	1,229,654	1,093,723
Net capitalized costs	**$1,339,970**	$1,347,922	$1,227,244

Note: Net capitalized costs reflect noncash write-downs of the Company's oil and natural gas properties, as discussed in Note 1.

Capital expenditures, including those not subject to amortization, related to oil and natural gas producing activities were as follows:

Years ended December 31,	**2012***	2011*	2010*
		(In thousands)	
Acquisitions:			
Proved properties	**$ 839**	$ 3,999	$ 89,733
Unproved properties	**31,109**	63,354	92,100
Exploration	**235,906**	41,775	33,226
Development	**275,959**	161,647	139,733
Total capital expenditures	**$543,813**	$270,775	$354,792

* Excludes net additions/(reductions) to property, plant and equipment related to the recognition of future liabilities for asset retirement obligations associated with the plugging and abandonment of oil and natural gas wells, as discussed in Note 10, of $(200,000), $(1.8) million and $11.1 million for the years ended December 31, 2012, 2011 and 2010, respectively.

The following summary reflects income resulting from the Company's operations of oil and natural gas producing activities, excluding corporate overhead and financing costs:

Years ended December 31,	**2012**	2011	2010
		(In thousands)	
Revenues:			
Sales to affiliates	**$ 35,966**	$ 93,713	$115,784
Sales to external customers	**412,651**	359,873	318,565
Production costs	**134,795**	140,606	127,403
Depreciation, depletion and amortization*	**157,078**	139,539	127,266
Write-downs of oil and natural gas properties	**391,800**	–	–
Pretax income (loss)	**(235,056)**	173,441	179,680
Income tax expense (benefit)	**(88,612)**	63,655	66,293
Results of operations for producing activities	**$(146,444)**	$109,786	$113,387

* Includes accretion of discount for asset retirement obligations of $3.3 million, $3.6 million and $3.2 million for the years ended December 31, 2012, 2011 and 2010, respectively, as discussed in Note 10.

Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The proved reserve estimates as of December 31, 2012, 2011 and 2010, were calculated using SEC Defined Prices. Other factors used in the proved reserve estimates are current estimates of well operating and future development costs, taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

The reserve estimates are prepared by internal engineers assigned to an asset team by geographic area. Senior management reviews and approves the reserve estimates to ensure they are materially accurate. In addition, the Company engaged Ryder Scott, an independent third party, to audit its proved reserve quantity estimates.

Estimates of economically recoverable oil, NGL and natural gas reserves and future net revenues therefrom are based upon a number of variable factors and assumptions. For these reasons, estimates of economically recoverable reserves and future net revenues may vary from actual results.

The Company's interests in oil, NGL and natural gas reserves are located in the United States and in and around the Gulf of Mexico.

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2012, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	27,005	7,342	379,827	97,651
Production	(3,694)	(828)	(33,214)	(10,058)
Extensions and discoveries	9,874	1,817	18,386	14,756
Improved recovery	–	–	–	–
Purchases of proved reserves	–	–	–	–
Sales of proved reserves	(39)	–	(2,307)	(423)
Revisions of previous estimates	307	(1,178)	(123,414)	(21,440)
Balance at end of year	33,453	7,153	239,278	80,486

Significant changes in proved reserves for the year ended December 31, 2012, include:

- Extension and discoveries of 14.8 MMBOE primarily due to drilling activity at the Company's Bakken, South Texas, and Paradox properties
- Revisions of previous estimates of (21.4) MMBOE, largely the result of lower natural gas prices resulting in a reduction of PDP and PUD reserves principally in the Company's Coalbed, Baker, Bowdoin, East Texas and Green River Basin natural gas properties

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2011, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	25,666	7,201	448,397	107,599
Production	(2,724)	(776)	(45,598)	(11,099)
Extensions and discoveries	4,717	1,421	28,221	10,842
Improved recovery	–	–	–	–
Purchases of proved reserves	223	16	54	247
Sales of proved reserves	–	–	–	–
Revisions of previous estimates	(877)	(520)	(51,247)	(9,938)
Balance at end of year	27,005	7,342	379,827	97,651

Significant changes in proved reserves for the year ended December 31, 2011, include:

- Extensions and discoveries of 10.8 MMBOE primarily due to drilling activity at the Company's Bakken and Big Horn properties
- Revisions of previous estimates of (9.9) MMBOE, largely the result of a reduction in PUD reserves of 8.9 MMBOE resulting principally in the Company's Bowdoin, Baker, Coalbed, East Texas and Big Horn Basin properties. The remaining negative revisions were a reduction in PDP natural gas reserves.

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2010, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	25,930	8,286	448,425	108,954
Production	(2,767)	(495)	(50,391)	(11,661)
Extensions and discoveries	2,793	596	36,191	9,421
Improved recovery	–	–	–	–
Purchases of proved reserves	911	68	55,119	10,165
Sales of proved reserves	(18)	–	(92)	(34)
Revisions of previous estimates	(1,183)	(1,254)	(40,855)	(9,246)
Balance at end of year	25,666	7,201	448,397	107,599

Significant changes in proved reserves for the year ended December 31, 2010, include:

- Extensions and discoveries of 9.4 MMBOE primarily due to drilling activity at the Company's Bakken, Baker, Bowdoin and east Texas properties
- Purchases of proved reserves of 10.2 MMBOE as a result of the Company's acquisition of natural gas properties in the Green River Basin in Wyoming, as discussed in Note 2
- Revisions of previous estimates of (9.2) MMBOE largely the result of negative performance revisions resulting primarily from new information gained from production history and developmental drilling activity in the Company's Bowdoin, south Texas, Baker and east Texas properties and removal of PUD reserves due to the five-year limitation rule, partially offset by positive revisions due to increased oil and natural gas prices

The following table summarizes the breakdown of the Company's proved reserves between proved developed and PUD reserves at December 31:

	2012	2011	2010
Proved developed reserves:			
Oil (MBbls)	**27,412**	23,653	22,352
NGL (MBbls)	**5,342**	5,225	4,234
Natural Gas (MMcf)	**218,259**	303,495	334,911
Total (MBOE)	**69,131**	79,460	82,404
PUD reserves:			
Oil (MBbls)	**6,041**	3,352	3,314
NGL (MBbls)	**1,811**	2,117	2,967
Natural Gas (MMcf)	**21,019**	76,332	113,486
Total (MBOE)	**11,355**	18,191	25,195
Total proved reserves:			
Oil (MBbls)	**33,453**	27,005	25,666
NGL (MBbls)	**7,153**	7,342	7,201
Natural Gas (MMcf)	**239,278**	379,827	448,397
Total (MBOE)	**80,486**	97,651	107,599

As of December 31, 2012, the Company had 11.4 MMBOE of PUD reserves, which is a decrease of 6.8 MMBOE from December 31, 2011. The decrease relates to the Company converting 3.9 MMBOE of its December 31, 2011, PUD reserves into proved developed reserves in 2012, requiring $58.4 million of drilling and completion capital in 2012 and 10.3 MMBOE of negative revisions applied to PUD locations primarily in the Company's natural gas properties. These changes were partially offset by 7.4 MMBOE of new PUD reserves primarily in the Company's oil properties. At December 31, 2012, the Company did not have any PUD locations that remained undeveloped for five years or more. Future development costs estimated to be spent in each of the next three years to develop PUD reserves as of December 31, 2012, are $147.5 million in 2013, $24.3 million in 2014 and $12.0 million in 2015.

The standardized measure of the Company's estimated discounted future net cash flows of total proved reserves associated with its various oil and natural gas interests at December 31 was as follows:

	2012	2011	2010
		(In thousands)	
Future cash inflows	**$3,696,200**	$4,188,000	$3,790,700
Future production costs	**1,536,500**	1,560,300	1,393,000
Future development costs	**301,600**	285,300	312,500
Future net cash flows before income taxes	**1,858,100**	2,342,400	2,085,200
Future income tax expense	**304,900**	531,100	432,800
Future net cash flows	**1,553,200**	1,811,300	1,652,400
10% annual discount for estimated timing of cash flows	**669,800**	832,500	756,300
Discounted future net cash flows relating to proved oil, NGL and natural gas reserves	**$ 883,400**	$ 978,800	$ 896,100

The following are the sources of change in the standardized measure of discounted future net cash flows by year:

	2012	2011	2010
		(In thousands)	
Beginning of year	**$ 978,800**	$ 896,100	$ 658,800
Net revenues from production	**(280,800)**	(301,500)	(270,000)
Net change in sales prices and production costs related to future production	**(406,300)**	82,300	362,400
Extensions and discoveries, net of future production-related costs	**355,300**	226,300	130,500
Improved recovery, net of future production-related costs	**–**	–	–
Purchases of proved reserves, net of future production-related costs	**–**	9,500	99,800
Sales of proved reserves	**(2,600)**	–	(500)
Changes in estimated future development costs	**37,600**	51,100	34,100
Development costs incurred during the current year	**77,700**	56,300	43,100
Accretion of discount	**121,400**	105,000	76,500
Net change in income taxes	**110,000**	(55,800)	(103,300)
Revisions of previous estimates	**(100,700)**	(92,900)	(132,000)
Other	**(7,000)**	2,400	(3,300)
Net change	**(95,400)**	82,700	237,300
End of year	**$ 883,400**	$ 978,800	$ 896,100

The estimated discounted future cash inflows from estimated future production of proved reserves were computed using prices as previously discussed. Future development and production costs attributable to proved reserves were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future income tax expenses were computed by applying statutory tax rates, adjusted for permanent differences and tax credits, to estimated net future pretax cash flows.

The standardized measure of discounted future net cash flows does not purport to represent the fair market value of oil and natural gas properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs. In addition, future realization of oil, NGL and natural gas prices over the remaining reserve lives may vary significantly from SEC Defined Prices.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

The following information includes the evaluation of disclosure controls and procedures by the Company's chief executive officer and the chief financial officer, along with any significant changes in internal controls of the Company.

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. The Company's disclosure controls and other procedures are designed to provide reasonable assurance that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The Company's disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including the Company's chief executive officer and chief financial officer, to allow timely decisions regarding required disclosure. The Company's management, with the participation of the Company's chief executive officer and chief financial officer, has evaluated the effectiveness of the Company's disclosure controls and procedures. Based upon that evaluation, the chief executive officer and the chief financial officer have concluded that, as of the end of the period covered by this report, such controls and procedures were effective at a reasonable assurance level.

Changes in Internal Controls

No change in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended December 31, 2012, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

The information required by this item is included in this Form 10-K at Item 8 – Management's Report on Internal Control Over Financial Reporting.

Attestation Report of the Registered Public Accounting Firm

The information required by this item is included in this Form 10-K at Item 8 – Report of Independent Registered Public Accounting Firm.

Item 9B. Other Information

None.

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is included in the last sentence of the fourth paragraph under the caption "Item 1. Election of Directors" and under the captions "Item 1. Election of Directors – Director Nominees," "Information Concerning Executive Officers," the first paragraph and the second and third sentences of the second paragraph under "Corporate Governance – Audit Committee," "Corporate Governance – Code of Conduct," the second sentence of the last paragraph under "Corporate Governance – Board Meetings and Committees" and "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement, which information is incorporated herein by reference.

Item 11. Executive Compensation

The information required by this item is included under the caption "Executive Compensation" in the Proxy Statement, which information is incorporated herein by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Equity Compensation Plan Information

The following table includes information as of December 31, 2012, with respect to the Company's equity compensation plans:

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 stockholders (1)	786,136 (2)	$18.17	6,213,269 (3)(4)
Equity compensation plans not approved by stockholders	N/A	N/A	N/A

(1) Consists of the Non-Employee Director Long-Term Incentive Compensation Plan, the Long-Term Performance-Based Incentive Plan and the Non-Employee Director Stock Compensation Plan.

(2) Consists of performance shares.

(3) 357,757 shares remain available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan in connection with grants of restricted stock, performance units, performance shares or other equity-based awards. 5,643,041 shares under the Long-Term Performance-Based Incentive Plan remain available for future issuance in connection with grants of restricted stock, performance units, performance shares or other equity-based awards.

(4) This amount also includes 212,471 shares available for issuance under the Non-Employee Director Stock Compensation Plan. Under this plan, in addition to a cash retainer, non-employee directors are awarded shares equal in value to $110,000 annually. A non-employee director may acquire additional shares under the plan in lieu of receiving the cash portion of the director's retainer or fees.

The remaining information required by this item is included under the caption "Security Ownership" in the Proxy Statement, which information is incorporated herein by reference.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is included under the captions "Related Person Transaction Disclosure," "Corporate Governance – Director Independence" and the second sentence of the third paragraph under "Corporate Governance – Board Meetings and Committees" in the Proxy Statement, which information is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

The information required by this item is included under the caption "Accounting and Auditing Matters" in the Proxy Statement, which information is incorporated herein by reference.

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Financial Statement Schedules and Exhibits

Index to Financial Statements and Financial Statement Schedules

1. Financial Statements

The following consolidated financial statements required under this item are included under Item 8 – Financial Statements and Supplementary Data. Page

2. Financial Statement Schedules

The following financial statement schedules are included in Part IV of this report. Page

MDU RESOURCES GROUP, INC.
Schedule I – Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Income and Comprehensive Income

Years ended December 31,	**2012**	2011	2010
		(In thousands)	
Operating revenues	**$472,302**	$518,268	$503,658
Operating expenses	**405,095**	450,579	431,293
Operating income	**67,207**	67,689	72,365
Other income	**3,925**	2,710	5,734
Interest expense	**17,297**	18,660	16,664
Income before income taxes	**53,835**	51,739	61,435
Income taxes	**11,798**	10,476	17,983
Equity in earnings (loss) of subsidiaries	**(42,791)**	171,763	197,207
Net income (loss)	**(754)**	213,026	240,659
Dividends declared on preferred stocks	**685**	685	685
Earnings (loss) on common stock	**$ (1,439)**	$212,341	$239,974
Comprehensive income (loss)	**$ (2,474)**	$197,286	$230,231

The accompanying notes are an integral part of these condensed financial statements.

MDU RESOURCES GROUP, INC.
Schedule I – Condensed Financial Information of Registrant (Unconsolidated)
Condensed Balance Sheets

December 31,	2012	2011
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	**$ 3,596**	$ 6,900
Receivables, net	**89,238**	67,761
Accounts receivable from subsidiaries	**2,957**	28,734
Inventories	**41,469**	42,596
Deferred income taxes	**3,685**	2
Prepayments and other current assets	**9,120**	12,154
Total current assets	**150,065**	158,147
Investments	**52,123**	47,835
Investment in subsidiaries	**2,253,294**	2,402,891
Property, plant and equipment	**1,581,776**	1,453,089
Less accumulated depreciation, depletion and amortization	**621,623**	605,510
Net property, plant and equipment	**960,153**	847,579
Deferred charges and other assets:		
Goodwill	**4,812**	4,812
Other	**155,483**	166,732
Total deferred charges and other assets	**160,295**	171,544
Total assets	**$3,575,930**	$3,627,996
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	**$ 108**	$ 107
Accounts payable	**42,149**	37,986
Accounts payable to subsidiaries	**6,423**	4,868
Taxes payable	**12,399**	18,304
Dividends payable	**171**	31,794
Accrued compensation	**10,282**	10,173
Other accrued liabilities	**29,490**	27,064
Total current liabilities	**101,022**	130,296
Long-term debt	**356,760**	280,781
Deferred credits and other liabilities:		
Deferred income taxes	**172,769**	137,751
Other liabilities	**297,131**	303,601
Total deferred credits and other liabilities	**469,900**	441,352
Commitments and contingencies		
Stockholders' equity:		
Preferred stocks	**15,000**	15,000
Common stockholders' equity:		
Common stock		
Authorized – 500,000,000 shares, $1.00 par value		
Issued – 189,369,450 shares in 2012 and 189,332,485 shares in 2011	**189,369**	189,332
Other paid-in capital	**1,039,080**	1,035,739
Retained earnings	**1,457,146**	1,586,123
Accumulated other comprehensive loss	**(48,721)**	(47,001)
Treasury stock at cost – 538,921 shares	**(3,626)**	(3,626)
Total common stockholders' equity	**2,633,248**	2,760,567
Total stockholders' equity	**2,648,248**	2,775,567
Total liabilities and stockholders' equity	**$3,575,930**	$3,627,996

The accompanying notes are an integral part of these condensed financial statements.

MDU RESOURCES GROUP, INC.
Schedule I – Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Cash Flows

Years ended December 31,	2012	2011	2010
		(In thousands)	
Net cash provided by operating activities	**$ 225,968**	$ 217,514	$ 185,887
Investing activities:			
Capital expenditures	**(150,337)**	(74,580)	(114,045)
Net proceeds from sale or disposition of property and other	**1,120**	720	625
Investments in and advances to subsidiaries	**(1,387)**	(5,701)	(1,636)
Investments from and advances from subsidiaries	**5,000**	–	–
Investments	**12**	–	(742)
Net cash used in investing activities	**(145,592)**	(79,561)	(115,798)
Financing activities:			
Issuance of short-term borrowings	**–**	–	20,000
Repayment of short-term borrowings	**–**	(20,000)	–
Issuance of long-term debt	**76,000**	–	–
Repayment of long-term debt	**(21)**	(107)	(107)
Proceeds from issuance of common stock	**88**	5,744	4,972
Dividends paid	**(159,768)**	(123,323)	(119,157)
Excess tax benefit on stock-based compensation	**21**	358	375
Net cash used in financing activities	**(83,680)**	(137,328)	(93,917)
Increase (decrease) in cash and cash equivalents	**(3,304)**	625	(23,828)
Cash and cash equivalents – beginning of year	**6,900**	6,275	30,103
Cash and cash equivalents – end of year	**$ 3,596**	$ 6,900	$ 6,275

The accompanying notes are an integral part of these condensed financial statements.

Notes to Condensed Financial Statements

Note 1 – Summary of Significant Accounting Policies

Basis of presentation The condensed financial information reported in Schedule I is being presented to comply with Rule 12-04 of Regulation S-X. The information is unconsolidated and is presented for the parent company only, which is comprised of MDU Resources Group, Inc. (the Company) and Montana-Dakota and Great Plains, public utility divisions of the Company. In Schedule I, investments in subsidiaries are presented under the equity method of accounting where the assets and liabilities of the subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded on the Condensed Balance Sheets. The income (loss) from subsidiaries is reported as equity in earnings (loss) of subsidiaries on the Condensed Statements of Income. The consolidated financial statements of MDU Resources Group, Inc. reflect certain businesses as discontinued operations. In Schedule I, amounts from discontinued operations have not been separately stated. These statements should be read in conjunction with the consolidated financial statements and notes thereto of MDU Resources Group, Inc.

Earnings (loss) per common share Please refer to the Consolidated Statements of Income of the registrant for earnings (loss) per common share. In addition, see Note 1 of Notes to Consolidated Financial Statements for information on the computation of earnings (loss) per common share.

Note 2 – Debt The Company has long-term debt obligations outstanding of $356.9 million at December 31, 2012, with annual maturities of $100,000 from 2013 to 2015, $50.1 million in 2016, $76.0 million in 2017 and $230.5 million scheduled to mature in years after 2017.

For more information on debt, see Note 9 of Notes to Consolidated Financial Statements.

Note 3 – Dividends The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $125.8 million, $96.1 million and $96.4 million for the years ended December 31, 2012, 2011 and 2010, respectively.

MDU RESOURCES GROUP, INC.
Schedule II – Consolidated Valuation and Qualifying Accounts
For the years ended December 31, 2012, 2011 and 2010

Description	Balance at Beginning of Year	Additions: Charged to Costs and Expenses	Additions: Other*	Deductions**	Balance at End of Year
			(In thousands)		
Allowance for doubtful accounts:					
2012	**$12,407**	**$7,064**	**$1,754**	**$10,407**	**$10,818**
2011	15,284	3,977	2,112	8,966	12,407
2010	16,649	5,044	2,300	8,709	15,284

* Allowance for doubtful accounts for companies acquired and recoveries.
** Uncollectible accounts written off.

All other schedules are omitted because of the absence of the conditions under which they are required, or because the information required is included in the Company's Consolidated Financial Statements and Notes thereto.

3. Exhibits

3(a) Restated Certificate of Incorporation of the Company, as amended, dated May 13, 2010, filed as Exhibit 3(a) to Form 10-Q for the quarter ended September 30, 2010, filed on November 3, 2010, in File No. 1-3480*

3(b) Company Bylaws, as amended and restated, on August 16, 2012, filed as Exhibit 3 to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*

4(a) Indenture, dated as of December 15, 2003, between the Company and The Bank of New York, as trustee, filed as Exhibit 4(f) to Form S-8 on January 21, 2004, in Registration No. 333-112035*

4(b) First Supplemental Indenture, dated as of November 17, 2009, between the Company and The Bank of New York Mellon, as trustee, filed as Exhibit 4(c) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

4(c) Centennial Energy Holdings, Inc. Master Shelf Agreement, dated April 29, 2005, among Centennial Energy Holdings, Inc. and the Prudential Insurance Company of America, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*

4(d) Letter Amendment No. 1 to Amended and Restated Master Shelf Agreement, dated May 17, 2006, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2006, filed on August 4, 2006, in File No. 1-3480*

4(e) MDU Resources Group, Inc. Credit Agreement, dated May 26, 2011, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, filed as Exhibit 4(e) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

4(f) First Amendment to Credit Agreement, dated October 4, 2012, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, filed as Exhibit 4 to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*

4(g) Centennial Energy Holdings, Inc. Credit Agreement, dated June 8, 2012, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Other Financial Institutions party thereto, filed as Exhibit 4 to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*

4(h) MDU Energy Capital, LLC Master Shelf Agreement, dated as of August 9, 2007, among MDU Energy Capital, LLC and the Prudential Insurance Company of America, filed as Exhibit 4 to Form 8-K dated August 16, 2007, filed on August 16, 2007, in File No. 1-3480*

4(i) Amendment No. 1 to Master Shelf Agreement, dated October 1, 2008, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America, and the holders of the notes thereunder, filed as Exhibit 4(b) to Form 10-Q for the quarter ended September 30, 2008, filed on November 5, 2008, in File No. 1-3480*

4(j) Indenture dated as of August 1, 1992, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 8-K dated August 12, 1992, in File No. 1-7196*

4(k) First Supplemental Indenture dated as of October 25, 1993, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes and the 7.5% Notes due November 15, 2031, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 10-Q for the quarter ended June 30, 1993, in File No. 1-7196*

4(l) Second Supplemental Indenture, dated January 25, 2005, between Cascade Natural Gas Corporation and The Bank of New York, as trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated January 25, 2005, filed on January 26, 2005, in File No. 1-7196*

4(m) Third Supplemental Indenture dated as of March 8, 2007, between Cascade Natural Gas Corporation and The Bank of New York Trust Company, N.A., as Successor Trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated March 8, 2007, filed on March 8, 2007, in File No. 1-7196*

+10(a) Supplemental Income Security Plan, as amended and restated November 12, 2009, filed as Exhibit 10(b) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(b) Director Compensation Policy, as amended February 14, 2013**

+10(c) Deferred Compensation Plan for Directors, as amended May 15, 2008, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2008, filed on August 7, 2008, in File No. 1-3480*

+10(d) Non-Employee Director Stock Compensation Plan, as amended May 12, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*

+10(e) MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan, as amended May 17, 2012, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*

+10(f) Long-Term Performance-Based Incentive Plan, as amended November 17, 2011, filed as Exhibit 10(h) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

+10(g) MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended March 1, 2012, and Rules and Regulations, as amended March 1, 2012, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2012, filed on May 4, 2012, in File No. 1-3480*

+10(h) Supplemental Executive Retirement Plan for John G. Harp, dated December 4, 2006, filed as Exhibit 10(ag) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(i) Employment Letter for John G. Harp, dated July 20, 2005, filed as Exhibit 10(ah) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(j) Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended November 14, 2012, filed as Exhibit 10.1 to Form 8-K dated November 14, 2012, filed on November 20, 2012, in File No. 1-3480*

+10(k) Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan as amended March 1, 2012, filed as Exhibit 10.2 to Form 8-K dated March 1, 2012, filed on March 6, 2012, in File No. 1-3480*

+10(l) Agreement for Termination of Change of Control Employment Agreement, dated June 15, 2010, by and between MDU Resources Group, Inc. and Terry D. Hildestad, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2010, filed on August 6, 2010, in File No. 1-3480*

+10(m) Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, filed as Exhibit 10.1 to Form 8-K dated August 12, 2010, filed on August 17, 2010, in File No. 1-3480*

+10(n) MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of January 4, 2013**

+10(o) Employment Letter for J. Kent Wells, dated March 9, 2011, filed as Exhibit 10(v) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

+10(p) MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as adopted November 17, 2011, filed as Exhibit 10(x) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

+10(q) Form of Agreement for Termination of Change of Control Employment Agreement, effective November 1, 2012, by and between MDU Resources Group, Inc. and William E. Schneider, John G. Harp, Steven L. Bietz, David L. Goodin, William R. Connors, Mark A. Del Vecchio, Nicole A. Kivisto, Cynthia J. Norland, Paul K. Sandness, Doran N. Schwartz and John P. Stumpf, filed as Exhibit 10(c) to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*

+10(r) MDU Resources Group, Inc. 401(k) Retirement Plan, as restated March 1, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*

+10(s) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 29, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2011, filed on May 5, 2011, in File No. 1-3480*

+10(t)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 30, 2011, filed as Exhibit 10(d) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*
+10(u)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*
+10(v)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 29, 2011, filed as Exhibit 10(ac) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*
+10(w)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated May 24, 2012, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*
+10(x)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*
+10(y)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*
+10(z)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 19, 2012**
12	Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends**
21	Subsidiaries of MDU Resources Group, Inc.**
23(a)	Consent of Independent Registered Public Accounting Firm**
23(b)	Consent of Ryder Scott Company, L.P.**
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
32	Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**
95	Mine Safety Disclosures**
99	Ryder Scott Company, L.P. report dated January 30, 2013**
101	The following materials from MDU Resources Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2012, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Common Stockholders' Equity, (v) the Consolidated Statements of Cash Flows, (vi) the Notes to Consolidated Financial Statements, tagged in summary and detail, (vii) Schedule I – Condensed Financial Information of Registrant, tagged in summary and detail and (viii) Schedule II – Consolidated Valuation and Qualifying Accounts, tagged in summary and detail

* Incorporated herein by reference as indicated.
** Filed herewith.
+ Management contract, compensatory plan or arrangement.

MDU Resources Group, Inc. agrees to furnish to the SEC upon request any instrument with respect to long-term debt that MDU Resources Group, Inc. has not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A) of Regulation S-K.

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.

MDU Resources Group, Inc.

Date: February 28, 2013

By: /s/ David L. Goodin
David L. Goodin
(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 in the capacities and on the date indicated.

Signature	Title	Date
/s/ David L. Goodin David L. Goodin (President and Chief Executive Officer)	Chief Executive Officer and Director	February 28, 2013
/s/ Doran N. Schwartz Doran N. Schwartz (Vice President and Chief Financial Officer)	Chief Financial Officer	February 28, 2013
/s/ Nicole A. Kivisto Nicole A. Kivisto (Vice President, Controller and Chief Accounting Officer)	Chief Accounting Officer	February 28, 2013
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 28, 2013
/s/ Thomas Everist Thomas Everist	Director	February 28, 2013
/s/ Karen B. Fagg Karen B. Fagg	Director	February 28, 2013
/s/ A. Bart Holaday A. Bart Holaday	Director	February 28, 2013
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 28, 2013
/s/ Thomas C. Knudson Thomas C. Knudson	Director	February 28, 2013
/s/ Richard H. Lewis Richard H. Lewis	Director	February 28, 2013
/s/ Patricia L. Moss Patricia L. Moss	Director	February 28, 2013
/s/ J. Kent Wells J. Kent Wells	Director	February 28, 2013
/s/ John K. Wilson John K. Wilson	Director	February 28, 2013

MDU RESOURCES
GROUP, INC.

1200 West Century Avenue

Mailing Address:
P.O. Box 5650
Bismarck, ND 58506-5650
(701) 530-1000

David L. Goodin
President and
Chief Executive Officer

March 13, 2013

To Our Stockholders:

Please join us for the 2013 Annual Meeting of Stockholders. The meeting will be held on Tuesday, April 23, 2013, at 11:00 a.m., Central Daylight Saving Time, at 909 Airport Road, Bismarck, North Dakota.

The formal matters are described in the accompanying Notice of Annual Meeting of Stockholders and Proxy Statement. We also will have a brief report on current matters of interest. Lunch will be served following the meeting.

We were pleased with the stockholder response for the 2012 Annual Meeting at which 89.72 percent of the common stock was represented in person or by proxy. We hope for an even greater representation at the 2013 meeting.

You may vote your shares by telephone, by the Internet, or by returning the enclosed proxy card. Representation of your shares at the meeting is very important. We urge you to submit your proxy promptly.

Brokers may not vote your shares on two of the three matters to be presented if you have not given your broker specific instructions as to how to vote. Please be sure to give specific voting instructions to your broker so that your vote can be counted.

All stockholders who find it convenient to do so are cordially invited and urged to attend the meeting in person. Registered stockholders will receive a request for admission ticket(s) with their proxy card that can be completed and returned to us postage-free. Stockholders whose shares are held in the name of a bank or broker will not receive a request for admission ticket(s). They should, instead, (1) call (701) 530-1000 to request an admission ticket(s), (2) bring a statement from their bank or broker showing proof of stock ownership as of February 25, 2013, to the annual meeting, and (3) present their admission ticket(s) and photo identification, such as a driver's license. Directions to the meeting will be included with your admission ticket.

I hope you will find it possible to attend the meeting.

Sincerely yours,

David L. Goodin

MDU RESOURCES GROUP, INC.

1200 West Century Avenue

Mailing Address:
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(701) 530-1000

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS TO BE HELD APRIL 23, 2013

Important Notice Regarding the Availability of Proxy Materials for the Stockholder Meeting to Be Held on April 23, 2013

The 2013 Notice of Annual Meeting and Proxy Statement and 2012 Annual Report to Stockholders are available at www.mdu.com/proxymaterials.

March 13, 2013

NOTICE IS HEREBY GIVEN that the Annual Meeting of Stockholders of MDU Resources Group, Inc. will be held at 909 Airport Road, Bismarck, North Dakota, on Tuesday, April 23, 2013, at 11:00 a.m., Central Daylight Saving Time, for the following purposes:

(1) Election of ten directors nominated by the board of directors for one-year terms;

(2) Ratification of the appointment of Deloitte & Touche LLP as the company's independent auditors for 2013;

(3) Approval, on a non-binding advisory basis, of the compensation of the company's named executive officers; and

(4) Transaction of any other business that may properly come before the meeting or any adjournment(s) thereof.

The board of directors has set the close of business on February 25, 2013, as the record date for the determination of common stockholders who will be entitled to notice of, and to vote at, the meeting and any adjournment(s) thereof.

All stockholders who find it convenient to do so are cordially invited and urged to attend the meeting in person. Registered stockholders will receive a request for admission ticket(s) with their proxy card that can be completed and returned to us postage-free. Stockholders whose shares are held in the name of a bank or broker will not receive a request for admission ticket(s). They should, instead, (1) call (701) 530-1000 to request an admission ticket(s), (2) bring a statement from their bank or broker showing proof of stock ownership as of February 25, 2013, to the annual meeting, and (3) present their admission ticket(s) and photo identification, such as a driver's license. Directions to the meeting will be included with your admission ticket. We look forward to seeing you.

By order of the Board of Directors,

Paul K. Sandness

Paul K. Sandness
Secretary

PROXY STATEMENT

The board of directors of MDU Resources Group, Inc. is furnishing this proxy statement beginning March 13, 2013, to solicit your proxy for use at our annual meeting of stockholders on April 23, 2013, and any adjournment(s) thereof. We are soliciting proxies principally by mail, but directors, officers, and employees of MDU Resources Group, Inc. or its subsidiaries may solicit proxies personally, by telephone, or by electronic media, without compensation other than their regular compensation. Okapi Partners LLC additionally will solicit proxies for approximately $7,000 plus out-of-pocket expenses. We will pay the cost of soliciting your proxy and reimburse brokers and others for forwarding proxy material to you.

The Securities and Exchange Commission's e-proxy rules allow companies to post their proxy materials on the Internet and provide only a Notice of Internet Availability of Proxy Materials to stockholders as an alternative to mailing full sets of proxy materials except upon request. For 2013, we have elected to use the Securities and Exchange Commission's full set delivery option, which means that while we are posting our proxy materials online, we are also mailing a full set of our proxy materials to our stockholders. We believe that mailing a full set of proxy materials will help ensure that a majority of outstanding shares of our common stock are present in person or represented by proxy at our meeting. We also hope to help maximize stockholder participation. Therefore, even if you previously consented to receiving your proxy materials electronically, you will receive a full set of proxy materials in the mail for this year's annual meeting. However, we will continue to evaluate the option of providing only a Notice of Internet Availability of Proxy Materials to some or all of our stockholders in the future.

VOTING INFORMATION

Who may vote? You may vote if you owned shares of our common stock at the close of business on February 25, 2013. You may vote each share that you owned on that date on each matter presented at the meeting and any adjournment(s) thereof. As of February 25, 2013, we had 188,830,529 shares of common stock outstanding entitled to one vote per share.

What am I voting on? You are voting on:

- election of ten directors nominated by the board of directors for one-year terms
- ratification of the appointment of Deloitte & Touche LLP as the company's independent auditors for 2013
- approval, on a non-binding advisory basis, of the compensation of the company's named executive officers and
- any other business that is properly brought before the meeting or any adjournment(s) thereof.

What vote is required to pass an item of business? A majority of our outstanding shares of common stock entitled to vote must be present in person or represented by proxy to hold the meeting.

If you hold shares through an account with a bank or broker, the bank or broker may vote your shares on some matters even if you do not provide voting instructions. Brokerage firms have the authority under the New York Stock Exchange rules to vote shares on certain matters when their customers do not provide voting instructions. However, on other matters, when the brokerage firm has not received voting instructions from its customers, the brokerage firm cannot vote the shares on that matter and a "broker non-vote" occurs. **This means that brokers may not vote your shares on items 1 and 3 if you have not given your broker specific instructions as to how to vote. Please be sure to give specific voting instructions to your broker so that your vote can be counted.**

Item 1 – Election of Directors

A majority of votes cast is required to elect a director in an uncontested election. A majority of votes cast means the number of votes cast "for" a director's election must exceed the number of votes cast "against" the director's election. "Abstentions" and "broker non-votes" do not count as votes cast "for" or "against" the director's election. In a contested election, which is an election in which the number of nominees for director exceeds the number of directors to be elected, directors will be elected by a plurality of the votes cast. If a nominee becomes unavailable for any reason or if a vacancy should occur before the election, which we do not anticipate, the proxies will vote your shares in their discretion for another person nominated by the board.

Our policy on majority voting for directors contained in our corporate governance guidelines requires any proposed nominee for re-election as a director to tender to the board, prior to nomination, his or her irrevocable resignation from the board that will be effective, in an uncontested election of directors only, upon:

- receipt of a greater number of votes "against" than votes "for" election at our annual meeting of stockholders and
- acceptance of such resignation by the board of directors.

Following certification of the stockholder vote, the nominating and governance committee will promptly recommend to the board whether or not to accept the tendered resignation. The board will act on the nominating and governance committee's recommendation no later than 90 days following the date of the annual meeting.

Item 2 – Ratification of the Appointment of Deloitte & Touche LLP as the Company's Independent Auditors for 2013

Approval of Item 2 requires the affirmative vote of a majority of our common stock present in person or represented by proxy at the meeting and entitled to vote on the proposal. Abstentions will count as votes "against" the proposal.

Item 3 – Approval, on a Non-Binding Advisory Basis, of the Compensation of the Company's Named Executive Officers

Approval of Item 3 requires the affirmative vote of a majority of our common stock present in person or represented by proxy at the meeting and entitled to vote on the item. Abstentions will count as votes "against" the item. Broker non-votes are not counted as voting power present and, therefore, are not counted in the vote.

Unless you specify otherwise when you submit your proxy, the proxies will vote your shares of common stock "for" all directors nominated by the board of directors and "for" items 2 and 3.

How do I vote? There are three ways to vote by proxy:

- by calling the toll free telephone number on the enclosed proxy card
- by using the Internet as described on the enclosed proxy card or
- by returning the enclosed proxy card in the envelope provided.

You may be able to vote by telephone or the Internet if your shares are held in the name of a bank or broker. Follow their instructions.

You may also vote in person at the meeting. However, if you are the beneficial owner of the shares, you must obtain a legal proxy from the holder of record of the shares, usually your bank or broker, and present it at the meeting. A legal proxy identifies you, states the number of shares you own, and gives you the right to vote those shares. Without a legal proxy we cannot identify you as the beneficial owner of the shares or know how many shares you have to vote.

Can I revoke my proxy? Yes.

If you are a stockholder of record, you can revoke your proxy by:

- filing written revocation with the corporate secretary before the meeting
- filing a proxy bearing a later date with the corporate secretary before the meeting or
- revoking your proxy at the meeting and voting in person.

ITEM 1. ELECTION OF DIRECTORS

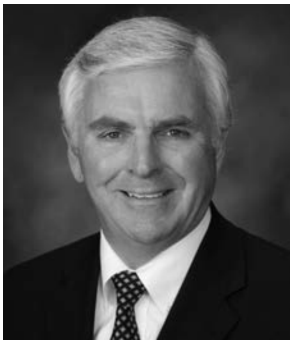
The board expresses its thanks to Terry D. Hildestad, who retired on January 3, 2013. He had served as president and chief executive officer of the company and as a director since August 17, 2006. He had served as president and chief operating officer from May 1, 2005 until August 17, 2006. He began his career with the company in 1974 at Knife River Corporation, where he served in several operating positions before becoming its chief executive officer in 1993 through April 2005.

The board also expresses its thanks to Richard H. Lewis for his service on the board, the audit committee, and the nominating and governance committee. Mr. Lewis also served on the compensation committee during his tenure. Mr. Lewis is not standing for reelection as a director after serving on the board since 2005.

All nominees for director are nominated to serve one-year terms until the annual meeting of stockholders in 2014 and until their respective successors are elected and qualified, or until their earlier resignation, removal from office, or death.

We have provided information below about our nominees, all of whom are incumbent directors, including their ages, years of service as directors, business experience, and service on other boards of directors, including any other directorships held during the past five years. We have also included information about each nominee's specific experience, qualifications, attributes, or skills that led the board to conclude that he or she should serve as a director of MDU Resources Group, Inc. at the time we file our proxy statement, in light of our business and structure. Unless we specifically note below, no corporation or organization referred to below is a subsidiary or other affiliate of MDU Resources Group, Inc.

Director Nominees



Thomas Everist
Age 63

Director Since 1995
Compensation Committee

Mr. Everist has served as president and chairman of The Everist Company, Sioux Falls, South Dakota, an aggregate, concrete, and asphalt production company, since April 15, 2002. He has been a managing member of South Maryland Creek Ranch, LLC, a land development company, since June 2006, and president of SMCR, Inc., an investment company, since June 2006. He was previously president and chairman of L.G. Everist, Inc., Sioux Falls, South Dakota, an aggregate production company, from 1987 to April 15, 2002. He held a number of positions in the aggregate and construction industries prior to assuming his current position with The Everist Company. He is a director of Showplace Wood Products, Sioux Falls, South Dakota, a custom cabinets manufacturer, and has been a director of Raven Industries, Inc., Sioux Falls, South Dakota, a general manufacturer of electronics, flow controls, and engineered films since 1996, and its chairman of the board since April 1, 2009. Mr. Everist has served as a director and chairman of the board of Everist Genomics, Inc., Ann Arbor, Michigan, which provides solutions for personalized medicines since 2002. He served as Everist Genomics' chief executive officer from August 2012 to December 2012. He was a director of Angiologix Inc., Mountain View, California, a medical diagnostic device company, from July 2010 through October 2011 when it was acquired by Everist Genomics, Inc. He has been a director of Bell, Inc., Sioux Falls, South Dakota, a manufacturer of folding cartons and packages, since April 2011.

Mr. Everist attended Stanford University where he received a bachelor's degree in mechanical engineering and a master's degree in construction management. He is active in the Sioux Falls community and currently serves as a director on the Sanford Health Foundation, a non-profit charitable health services organization, and as a member of the Council of Advisors for Searching for Solutions Institute, a non-profit public foundation that provides leaders with resources to address critical social issues. From July 2001 to June 2006, he served on the South Dakota Investment Council, the state agency responsible for prudently investing state funds.

The board concluded that Mr. Everist should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. A significant portion of MDU Resources Group, Inc.'s earnings is derived from its construction services and aggregate mining businesses. Mr. Everist has considerable business experience in this area, with more than 39 years in the aggregate and construction materials industry. He has also demonstrated success in his business and leadership skills, serving as president and chairman of his companies for over 25 years. We value other public company board service. Mr. Everist has experience serving as a director and now chairman of another public company, which enhances his contributions to our board. His leadership skills and experience with his own companies and on other boards enable him to be an effective board member and compensation committee chairman. Mr. Everist is our longest serving board member, providing 18 years of board experience as well as extensive knowledge of our business.

PROXY

Karen B. Fagg

Age 59

Director Since 2005
Nominating and Governance Committee
Compensation Committee

Ms. Fagg served as vice president of DOWL LLC, d/b/a DOWL HKM, an engineering and design firm, from April 2008 until her retirement on December 31, 2011. Ms. Fagg was president from April 1, 1995 through March 2008, and chairman and majority owner from June 2000 through March 2008 of HKM Engineering, Inc., Billings, Montana, an engineering and physical science services firm. HKM Engineering, Inc. merged with DOWL LLC on April 1, 2008. Ms. Fagg was employed with MSE, Inc., Butte, Montana, an energy research and development company, from 1976 through 1988, and from 1993 to April 1995 she served as vice president of operations and corporate development director. From 1989 through 1992, Ms. Fagg served a four-year term as director of the Montana Department of Natural Resources and Conservation, Helena, Montana, the state agency charged with promoting stewardship of Montana's water, soil, energy, and rangeland resources; regulating oil and gas exploration and production; and administering several grant and loan programs.

Ms. Fagg has a bachelor's degree in mathematics from Carroll College in Helena, Montana. She served on the board for St. Vincent's Healthcare from October 2003 until October 2009, including a term as board chair, on the board of Deaconess Billings Clinic Health System from 1994 to 2002, as a member of the Board of Trustees of Carroll College from 2005 through 2010, and on the board of advisors of the Charles M. Bair Family Trust from 2008 to July 2011, including a term as board chair. She has been a member of the board of directors of the Billings Chamber of Commerce since July 2009 and a member of the Billings Catholic School Board since December 2011. From 2007 until December 31, 2011, she was a member of the Montana State University Engineering Advisory Council, whose responsibilities include evaluating the mission and goals of the College of Engineering and assisting in the development and implementation of the college's strategic plan. From 2002 through 2006, she served on the Montana Board of Investments, the state agency responsible for prudently investing state funds. From 2001 to 2005, she served on the board of Montana State University's Advanced Technology Park. From 1998 to 2007, she served on the ZooMontana Board and as vice chair from 2005 to 2006.

The board concluded that Ms. Fagg should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. Construction and engineering, energy, and the responsible development of natural resources are all important aspects of our business. Ms. Fagg has business experience in all these areas, including 17 years of construction and engineering experience at DOWL HKM and its predecessor, HKM Engineering, Inc., where she served as vice president, president, and chairman. Ms. Fagg has also had 14 years of experience in energy research and development at MSE, Inc., where she served as vice president of operations and corporate development director, and four years focusing on stewardship of natural resources as director of the Montana Department of Natural Resources and Conservation. In addition to her industry experience, Ms. Fagg brings to our board 13 years of business leadership and management experience as president and chairman of her own company, as well as knowledge and experience acquired through her service on a number of Montana state and community boards.

David L. Goodin

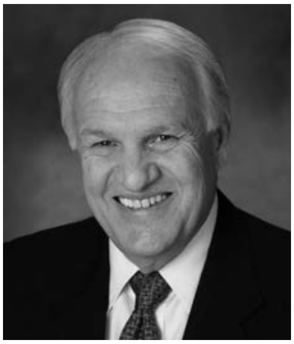
Age 51

Director Since January 4, 2013
President and Chief Executive Officer

Mr. Goodin was elected president and chief executive officer and a director of the company effective January 4, 2013. Prior to that, he served as chief executive officer and president of Intermountain Gas Company effective October 2008, chief executive officer of Cascade Natural Gas Corporation, Montana-Dakota Utilities Co., and Great Plains Natural Gas Co. effective June 2008, president of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. effective March 2008, and president of Cascade Natural Gas Corporation effective July 2007. He began his career with the company in 1983 at Montana-Dakota Utilities Co., where he served as a division electrical engineer effective May 1983, division electric superintendent effective February 1989, electric systems supervisor effective August 1993, electric systems manager effective April 1999, vice president-operations effective January 2000, and executive vice president-operations and acquisitions effective January 2007. He additionally serves as an executive officer and as chairman of the company's principal subsidiaries and of the managing committees of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co.

Mr. Goodin has a bachelor of science degree in electrical and electronics engineering from North Dakota State University, a masters in business administration from the University of North Dakota, and has completed the Advanced Management Program at Harvard School of Business. Mr. Goodin is a registered professional engineer in North Dakota. He is a member of the U.S. Bancorp Western North Dakota Advisory Board. Mr. Goodin is involved in numerous civic organizations, including serving on the board of directors of Sanford Bismarck, the Missouri Valley YMCA, and as trustee for the Bismarck State College Foundation. He is a past board member of several industry associations, including the American Gas Association, the Edison Electric Institute, the North Central Electric Association, the Midwest ENERGY Association, and the North Dakota Lignite Council. Mr. Goodin received the University of Mary Entrepreneurship Award in 2009.

The board concluded that Mr. Goodin should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. As chief executive officer of MDU Resources Group, Inc., Mr. Goodin is one of only two officers of the company to sit on our board. With over 29 years of significant, hands-on experience at our company, Mr. Goodin's long history and deep knowledge and understanding of MDU Resources Group, Inc., its operating companies, and its lines of business will bring continuity to the board. Mr. Goodin has demonstrated his leadership abilities and his commitment to our company through his long service to the company and more recently as chief executive officer and president of the four utility companies. He demonstrated strong leadership skills in integrating Cascade Natural Gas Corporation and Intermountain Gas Company while meeting and exceeding profitability goals. The board's unanimous election of Mr. Goodin to succeed Mr. Hildestad as our president and chief executive officer was a result of our comprehensive succession planning process led by the board of directors during which the board had the opportunity to interact with and evaluate our executive officers. The board selected Mr. Goodin because it became clear to the board through this process that he had the strategic vision, operational experience, passion, and values to lead the future growth of the company. The board believes these characteristics make him well-suited to serve on our board, particularly in this challenging economic environment.



A. Bart Holaday

Age 70

Director Since 2008
Audit Committee
Nominating and Governance Committee

Mr. Holaday headed the Private Markets Group of UBS Asset Management and its predecessor entities for 15 years prior to his retirement in 2001, during which time he managed more than $19 billion in investments. Prior to that he was vice president and principal of the InnoVen Venture Capital Group, a venture capital investment firm. He was founder and president of Tenax Oil and Gas Corporation, an onshore Gulf Coast exploration and production company, from 1980 through 1982. He has four years of senior management experience with Gulf Oil Corporation, a global energy and petrochemical company, and eight years of senior management experience with the federal government, including the Department of Defense, Department of the Interior, and the Federal Energy Administration. He is currently the president and owner of Dakota Renewable Energy Fund, LLC, which invests in small companies in North Dakota. He is a member of the investment advisory board of Commons Capital LLC, a venture capital firm; is a director of Hull Investments, LLC, a private entity that combines nonprofit activities and investments; is a member of the board of directors of Adams Street Partners, LLC, a private equity investment firm, Alerus Financial, a financial services company, Jamestown College, the United States Air Force Academy Endowment (former chairman), the Falcon Foundation (director and former vice president), which provides scholarships to Air Force Academy applicants, the Center for Innovation Foundation at the University of North Dakota (trustee and former chairman) and the University of North Dakota Foundation; is chairman and chief executive officer of the Dakota Foundation, a nonprofit foundation that fosters social entrepreneurship; and is a member of the board of trustees for The Colorado Springs Child Nursery Centers Foundation, a non-profit organization that supports the operations of Early Connections Learning Centers, a non-profit child care organization in Colorado, and Discover Goodwill of southern and western Colorado, a non-profit organization providing job training, placement, and retention programs for people transitioning from welfare to work. He is a past member of the board of directors of the National Venture Capital Association, Walden University, and the U.S. Securities and Exchange Commission advisory committee on the regulation of capital markets.

Mr. Holaday has a bachelor's degree in engineering sciences from the U.S. Air Force Academy. He was a Rhodes Scholar, earning a bachelor's degree and a master's degree in politics, philosophy, and economics from Oxford University. He also earned a law degree from George Washington Law School and is a Chartered Financial Analyst. In 2005, he was awarded an honorary Doctor of Letters from the University of North Dakota.

The board concluded that Mr. Holaday should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. MDU Resources Group, Inc. has significant operations in the natural gas and oil industry where Mr. Holaday has knowledge and experience. He founded and served as president of Tenax Oil and Gas Corporation. He has four years experience in senior management with Gulf Oil Corporation and 16 years of experience managing private equity investments, including investments in oil and gas, as the head of the Private Markets Group of UBS Asset Management and its predecessor organizations. This business experience demonstrates his leadership skills and success in the oil and gas industry.
Mr. Holaday brings to the board his extensive finance and investment experience, as well as his business development skills acquired through his work at UBS Asset Management, Tenax Oil and Gas Corporation, Gulf Oil Corporation, and several private equity investment firms. This will enhance the knowledge of the board and provide useful insights and guidance to management in connection not only with our natural gas and oil business, but with all of our businesses.

PROXY

Dennis W. Johnson

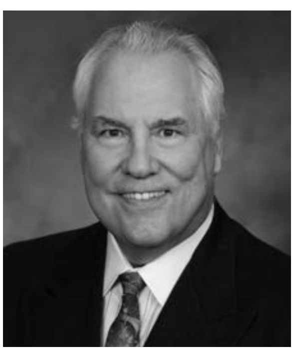
Age 63

Director Since 2001
Audit Committee

Mr. Johnson is chairman, chief executive officer, and president of TMI Corporation, and chairman and chief executive officer of TMI Systems Design Corporation, TMI Transport Corporation, and TMI Storage Systems Corporation, all of Dickinson, North Dakota, manufacturers of casework and architectural woodwork. He has been employed at TMI since 1974 serving as president or chief executive officer since 1982. Mr. Johnson is serving his thirteenth year as president of the Dickinson City Commission. He served as a director of the Federal Reserve Bank of Minneapolis from 1993 to 1998. He is a past member and chairman of the Theodore Roosevelt Medora Foundation.

Mr. Johnson has a bachelor of science degree in electrical and electronics engineering, as well as a master of science degree in industrial engineering from North Dakota State University. He has served on numerous industry, state, and community boards, including the North Dakota Workforce Development Council (chairperson), the Decorative Laminate Products Association, the North Dakota Technology Corporation, St. Joseph Hospital Life Care Foundation, St. John Evangelical Lutheran Church, Dickinson State University Foundation, the executive operations committee of the University of Mary Harold Schafer Leadership Center, the Dickinson United Way, and the business advisory council of the Steffes Corporation, a metal manufacturing and engineering firm. He also served on North Dakota Governor Sinner's Education Action Commission, the North Dakota Job Service Advisory Council, the North Dakota State University President's Advisory Council, North Dakota Governor Schafer's Transition Team, and chaired North Dakota Governor Hoeven's Transition Team. He has received numerous awards including the 1991 Regional Small Business Person of the Year Award and the Greater North Dakotan Award.

The board concluded that Mr. Johnson should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. Mr. Johnson has over 38 years of experience in business management, manufacturing, and finance, and has demonstrated his success in these areas, holding positions as chairman, president, and chief executive officer of TMI for 31 years, as well as through his prior service as a director of the Federal Reserve Bank of Minneapolis. His finance experience and leadership skills enable him to make valuable contributions to our audit committee, which he has chaired for nine years. As a result of his service on a number of state and local organizations in North Dakota, Mr. Johnson has significant knowledge of local, state, and regional issues involving North Dakota, a state where we have significant operations and assets.



Thomas C. Knudson

Age 66

Director Since 2008
Compensation Committee

Mr. Knudson has been president of Tom Knudson Interests since its formation on January 14, 2004. Tom Knudson Interests provides consulting services in energy, sustainable development, and leadership. Mr. Knudson began employment with Conoco Oil Company (Conoco) in May 1975 and retired in 2004 from Conoco's successor, ConocoPhillips, as senior vice president of human resources and government affairs and communications. Mr. Knudson served as a member of ConocoPhillips' management committee. His diverse career at Conoco and ConocoPhillips included engineering, operations, business development, and commercial assignments. He was the founding chairman of the Business Council for Sustainable Development in both the United States and the United Kingdom. He has been a director of Bristow Group Inc. since June 2004 and its chairman of the board of directors since August 2006, and was a director of Natco Group Inc. from April 2005 to November 2009 and Williams Partners LP from November 2005 to September 2007. Bristow Group Inc. is a leading provider of helicopter services to the offshore oil industry. Natco Group Inc. is a leading manufacturer of oil and gas processing equipment. Williams Partners LP owns natural gas gathering, transportation, processing, and treating assets, and also has natural gas liquids fractionating and storage assets.

Mr. Knudson has a bachelor's degree in aerospace engineering from the U.S. Naval Academy and a master's degree in aerospace engineering from the U.S. Naval Postgraduate School. He served as a naval aviator, flying combat missions in Vietnam, and was a lieutenant commander in 1974 when he was honorably discharged. He has served as an adjunct professor at the Jones Graduate School of Management at Rice University. Mr. Knudson has served on the boards of a number of petroleum industry associations, Covenant House Texas, and The Houston Museum of Natural Science. He has served on the National Council of Methodist Neurological Institute since October 2011, as a Trustee of the Episcopal Seminary of the Southwest, Austin, Texas, since February 2012, and as a board member of the National Association of Corporate Directors (NACD), Texas Tri-Cities Chapter, since December 2012. He holds the designation of Board Leadership Fellow from the NACD.

The board concluded that Mr. Knudson should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. A significant portion of our earnings is derived from natural gas and oil production and the transportation, storage, and gathering of natural gas. Mr. Knudson has extensive knowledge and experience in this industry as a result of his prior employment with Conoco and ConocoPhillips, as well as through his service on the boards of Natco Group Inc. and Williams Partners LP. Mr. Knudson has a broad background in engineering, operations, and business development, as well as service on the management committee at Conoco and ConocoPhillips, which bring additional experience and perspective to our board. His service as senior vice president of human resources at ConocoPhillips makes him an excellent fit for our compensation committee. Sustainable business development is also an important aspect of our business, and Mr. Knudson, as the founding chairman of the Business Council for Sustainable Development, brings to our board significant experience and knowledge in this area. Mr. Knudson also has significant knowledge of local, state, and regional issues involving Texas, a state where we have important operations and assets.

Patricia L. Moss
Age 59

Director Since 2003
Compensation Committee
Nominating and Governance Committee

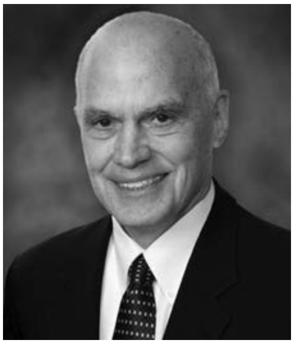
Ms. Moss served as the president and chief executive officer of Cascade Bancorp, a financial holding company in Bend, Oregon, from 1998 to January 3, 2012. She served as the chief executive officer of Cascade Bancorp's principal subsidiary, Bank of the Cascades, from 1993 to January 3, 2012, serving also as president from 1993 to 2003. From 1987 to 1998, Ms. Moss served as chief operating officer, chief financial officer, and corporate secretary of Cascade Bancorp. Ms. Moss has been a director of Cascade Bancorp since 1993 and a director of Bank of the Cascades since 1998 and was elected vice chairman of both boards effective January 3, 2012. Ms. Moss also serves as a director of the Oregon Investment Fund Advisory Council, a state-sponsored program to encourage the growth of small businesses within Oregon, co-chairs the Oregon Growth Board, a state agency created to provide recommendations to connect businesses to sources of capital, and serves on the City of Bend's Juniper Ridge management advisory board.

Ms. Moss graduated magna cum laude with a bachelor of science degree in business administration from Linfield College in Oregon and did master's studies at Portland State University. She received commercial banking school certification at the ABA Commercial Banking School at the University of Oklahoma. She served as a director of the Oregon Business Council, whose mission is to mobilize business leaders to contribute to Oregon's quality of life and economic prosperity; the Cascades Campus Advisory Board of the Oregon State University; the North Pacific Group, Inc., a wholesale distributor of building materials, industrial and hardwood products, and other specialty products; the Aquila Tax Free Trust of Oregon, a mutual fund created especially for the benefit of Oregon residents; Clear Choice Health Plans Inc., a multi-state insurance company; and as a director and chair of the St. Charles Medical Center.

In August 2009, the Federal Deposit Insurance Corporation and the Oregon Division of Finance and Corporate Securities entered into a consent agreement with Bank of the Cascades that requires the bank to develop and adopt a plan to maintain the capital necessary for it to be "well-capitalized," to improve its lending policies and its allowance for loan losses, to increase its liquidity, to retain qualified management, and to increase the participation of its board of directors in the affairs of the bank. In October 2009, the bank's parent, Cascade Bancorp, entered into a written agreement with the Federal Reserve Bank of San Francisco and the Oregon Division relating largely to improving the financial condition of Cascade Bancorp and the Bank of the Cascades. Cascade Bancorp reported in its third quarter 2012 Form 10-Q that at December 31, 2011, Cascade Bancorp and the Bank did not meet the written agreement's leverage ratio requirement and as a result they had filed a required update to their capital plan, which was accepted by their regulators. On September 30, 2012, Bancorp and the Bank had met this requirement. The order remains in place until lifted by the regulators.

The board concluded that Ms. Moss should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. A significant portion of MDU Resources Group, Inc.'s utility, construction services, and contracting operations are located in the Pacific Northwest. Ms. Moss has first-hand business experience and knowledge of the Pacific Northwest economy and local, state, and regional issues through her executive positions at Cascade Bancorp and Bank of the Cascades, where she gained over 30 years of experience. Ms. Moss provides to our board her experience in finance and banking, as well as her experience in business development through her work at Cascade Bancorp and on the Oregon Investment Advisory Council, the Oregon Business Council, and the Oregon Growth Board. This business experience demonstrates her leadership abilities and success in the finance and banking industry. Ms. Moss is also certified as a Senior Professional in Human Resources, which makes her well-suited for our compensation committee. In deciding that Ms. Moss should be renominated as a director, the board was mindful of the consent agreement with Bank of the Cascades, but concluded that Ms. Moss brought the many skills and experiences discussed above to our board and had proved herself to be a dedicated and hard-working director.

PROXY



Harry J. Pearce

Age 70

Director Since 1997
Chairman of the Board

Mr. Pearce was elected chairman of the board of the company on August 17, 2006. Prior to that, he served as lead director effective February 15, 2001, and was vice chairman of the board from November 16, 2000 until February 15, 2001. Mr. Pearce has been a director of Marriott International, Inc., a major hotel chain, since 1995. He was a director of Nortel Networks Corporation, a global telecommunications company, from January 11, 2005 to August 10, 2009, serving as chairman of the board from June 29, 2005. He retired on December 19, 2003, as chairman of Hughes Electronics Corporation, a General Motors Corporation subsidiary and provider of digital television entertainment, broadband satellite network, and global video and data broadcasting. He had served as chairman since June 1, 2001. Mr. Pearce was vice chairman and a director of General Motors Corporation, one of the world's largest automakers, from January 1, 1996 to May 31, 2001, and was general counsel from 1987 to 1994. He served on the President's Council on Sustainable Development and co-chaired the President's Commission on the United States Postal Service. Prior to joining General Motors, he was a senior partner in the Pearce & Durick law firm in Bismarck, North Dakota. Mr. Pearce is a director of the United States Air Force Academy Endowment and a member of the Advisory Board of the University of Michigan Cancer Center. He is a Fellow of the American College of Trial Lawyers and a member of the International Society of Barristers. He also serves on the Board of Trustees of Northwestern University. He has served as a chairman or director on the boards of numerous nonprofit organizations, including as chairman of the board of Visitors of the U.S. Air Force Academy, chairman of the National Defense University Foundation, and chairman of the Marrow Foundation. Mr. Pearce received a bachelor's degree in engineering sciences from the U.S. Air Force Academy and a juris doctor degree from Northwestern University's School of Law.

The board concluded that Mr. Pearce should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. MDU Resources Group, Inc. values public company leadership and the experience directors gain through such leadership. Mr. Pearce is recognized nationally, as well as in the State of North Dakota, as a business leader and for his business acumen. He has multinational business management experience and proven leadership skills through his position as vice chairman at General Motors Corporation, as well as through his extensive service on the boards of large public companies, including Marriott International, Inc.; Hughes Electronics Corporation, where he was chairman; and Nortel Networks Corporation, where he also was chairman. He also brings to our board his long experience as a practicing attorney. In addition, Mr. Pearce is focused on corporate governance issues and is the founding chair of the Chairmen's Forum, an organization comprised of non-executive chairmen of publicly-traded companies. Participants in the Chairmen's Forum discuss ways to enhance the accountability of corporations to owners and promote a deeper understanding of independent board leadership and effective practices of board chairmanship. The board also believes that Mr. Pearce's values and commitment to excellence make him well-suited to serve as chairman of our board.

J. Kent Wells

Age 56

Director Since January 4, 2013
Vice Chairman of the Corporation
President and Chief Executive Officer
of Fidelity Exploration & Production Company

Mr. Wells was elected vice chairman of the company and a director effective January 4, 2013, and continues to serve as president and chief executive officer of Fidelity Exploration & Production Company, our natural gas and oil production business, the position for which he was hired effective May 2, 2011. Prior to that he was senior vice president of exploration and production for BP America, Inc. (BP) from June 2007 until October 2010, when he was named BP's group senior vice president for global deepwater response until March 31, 2011. He also served as general manager of Abu Dhabi Company for Onshore Oil Operations from February 2005 until June 2007; vice president, Gulf of Mexico shelf, for BP from 2002 to 2005; vice president, Rockies, for BP from 2000 to 2002; general manager of Crescendo Resources LP from 1997 to 2000; manager, Hugoton, for Amoco Production Company, Inc. (Amoco) from 1993 to 1996; manager, operations, for Amoco in 1993; resource manager for Amoco from 1988 to 1993; executive assistant for Amoco from 1987 to 1988; engineering supervisor for Amoco Canada Petroleum Company (Amoco Canada) from 1983 to 1987; and petroleum engineer for Amoco Canada from 1979 to 1983. Mr. Wells received a bachelor's degree in mechanical engineering from the Queen's University, Kingston, Ontario, Canada in 1979.

The board concluded that Mr. Wells should serve as director of MDU Resources Group, Inc. in light of our business and structure, at the time we file our proxy statement for the following reasons. A significant portion of our earnings is derived from natural gas and oil production. One of the company's strategic objectives is to achieve product diversity in the midstream segment of the oil and gas industry. Mr. Wells brings to our board significant experience and knowledge of the oil and gas business, including the midstream segment. He has more than 33 years of natural gas and oil experience, including several years in senior leadership positions at BP, the world's third largest integrated oil company, and a publicly traded company. He was senior vice president of exploration and production for BP's U.S. natural gas operations from 2007 until October 2010 with responsibility for BP's onshore natural gas business throughout the United States, encompassing both exploration and production, and midstream business. His strong track record in natural gas and oil production includes experience in shale formations similar to the company's current development focus. He has firsthand experience in the Rockies and Texas, where a large portion of Fidelity Exploration & Production Company's reserves are concentrated. Mr. Wells' combination of expertise and experience, along with his success in leadership roles with a large publicly traded company, will complement the skills of the current board members.

John K. Wilson
Age 58

Director Since 2003
Audit Committee

Mr. Wilson was president of Durham Resources, LLC, a privately held financial management company, in Omaha, Nebraska, from 1994 to December 31, 2008. He previously was president of Great Plains Energy Corp., a public utility holding company and an affiliate of Durham Resources, LLC, from 1994 to July 1, 2000. He was vice president of Great Plains Natural Gas Co., an affiliate company of Durham Resources, LLC, until July 1, 2000. The company bought Great Plains Energy Corp. and Great Plains Natural Gas Co. on July 1, 2000. Mr. Wilson also served as president of the Durham Foundation and was a director of Bridges Investment Fund, a mutual fund, and the Greater Omaha Chamber of Commerce. He is presently a director of HDR, Inc., an international architecture and engineering firm, Tetrad Corporation, a privately held investment company, both based in Omaha, and serves on the advisory board of Duncan Aviation, an aircraft service provider, headquartered in Lincoln, Nebraska. He currently serves as executive director of the Robert B. Daugherty Charitable Foundation, Omaha, Nebraska, and formerly served on the advisory board of U.S. Bank NA Omaha.

Mr. Wilson is a certified public accountant, on inactive status. He received his bachelor's degree in business administration, cum laude, from the University of Nebraska – Omaha. During his career, he was an audit manager at Peat, Marwick, Mitchell (now known as KPMG), controller for Great Plains Natural Gas Co., and chief financial officer and treasurer for all Durham Resources entities.

The board concluded that Mr. Wilson should serve as a director of MDU Resources Group, Inc., in light of our business and structure, at the time we file our proxy statement for the following reasons. Mr. Wilson has an extensive background in finance and accounting, as well as extensive experience with mergers and acquisitions, through his education and work experience at a major accounting firm and his later positions as controller and vice president of Great Plains Natural Gas Co., president of Great Plains Energy Corp., and president, chief financial officer, and treasurer for Durham Resources, LLC and all Durham Resources entities. The electric and natural gas utility business was our core business when our company was founded in 1924. That business now operates through four utilities: Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company. Mr. Wilson is our only non-employee director with direct experience in this area through his prior positions at Great Plains Natural Gas Co. and Great Plains Energy Corp. In addition, Mr. Wilson's extensive finance and accounting experience make him well-suited for our audit committee.

The board of directors recommends a vote "for" each nominee.

A majority of votes cast is required to elect a director in an uncontested election. A majority of votes cast means the number of votes cast "for" a director's election must exceed the number of votes cast "against" the director's election. "Abstentions" and "broker non-votes" do not count as votes cast "for" or "against" the director's election. In a contested election, which is an election in which the number of nominees for director exceeds the number of directors to be elected and which we do not anticipate, directors will be elected by a plurality of the votes cast.

Unless you specify otherwise when you submit your proxy, the proxies will vote your shares of common stock "for" all directors nominated by the board of directors. If a nominee becomes unavailable for any reason or if a vacancy should occur before the election, which we do not anticipate, the proxies will vote your shares in their discretion for another person nominated by the board.

Our policy on majority voting for directors contained in our corporate governance guidelines requires any proposed nominee for re-election as a director to tender to the board, prior to nomination, his or her irrevocable resignation from the board that will be effective, in an uncontested election of directors only, upon:

- receipt of a greater number of votes "against" than votes "for" election at our annual meeting of stockholders and
- acceptance of such resignation by the board of directors.

Following certification of the stockholder vote, the nominating and governance committee will promptly recommend to the board whether or not to accept the tendered resignation. The board will act on the nominating and governance committee's recommendation no later than 90 days following the date of the annual meeting.

Brokers may not vote your shares on the election of directors if you have not given your broker specific instructions as to how to vote. Please be sure to give specific voting instructions to your broker so that your vote can be counted.

ITEM 2. RATIFICATION OF INDEPENDENT AUDITORS

The audit committee at its February 2013 meeting appointed Deloitte & Touche LLP as our independent auditors for fiscal year 2013. The board of directors concurred with the audit committee's decision. Deloitte & Touche LLP has served as our independent auditors since fiscal year 2002.

Although your ratification vote will not affect the appointment or retention of Deloitte & Touche LLP for 2013, the audit committee will consider your vote in determining its appointment of our independent auditors for the next fiscal year. The audit committee, in appointing our independent auditors, reserves the right, in its sole discretion, to change an appointment at any time during a fiscal year if it determines that such a change would be in our best interests.

A representative of Deloitte & Touche LLP will be present at the annual meeting and will be available to respond to appropriate questions. We do not anticipate that the representative will make a prepared statement at the meeting; however, he or she will be free to do so if he or she chooses.

The board of directors recommends a vote "for" the ratification of Deloitte & Touche LLP as our independent auditors for 2013.

Ratification of the appointment of Deloitte & Touche LLP as our independent auditors for 2013 requires the affirmative vote of a majority of our common stock present in person or represented by proxy at the meeting and entitled to vote on the proposal. Abstentions will count as votes against this proposal.

ACCOUNTING AND AUDITING MATTERS

Fees

The following table summarizes the aggregate fees that our independent auditors, Deloitte & Touche LLP, billed or are expected to bill us for professional services rendered for 2012 and 2011:

	2012	2011*
Audit Fees(a)	$2,400,000	$2,456,046
Audit-Related Fees(b)	63,110	216,410
Tax Fees(c)	23,566	0
All Other Fees(d)	0	0
Total Fees(e)	$2,486,676	$2,672,456
Ratio of Tax and All Other Fees to Audit and Audit-Related Fees	0.96%	0.00%

* The 2011 amounts were adjusted from amounts shown in the 2012 proxy statement to reflect actual amounts.

(a) Audit fees for 2012 and 2011 consisted of services rendered for the audit of our annual financial statements, reviews of quarterly financial statements, statutory and regulatory audits, compliance with loan covenants, reviews of financial statements for MDU Construction Services Group, Inc. and subsidiaries, agreed upon procedures associated with the annual submission of financial assurance to the North Dakota Department of Health, filing Form S-3 registration statements (2011 only), and work related to responding to a comment letter from the Securities and Exchange Commission (2011 only).

(b) Audit-related fees for 2012 and 2011 are associated with accounting research assistance, workpaper review requested by the Idaho Public Utilities Commission (2012 only), the compliance audit for the U.S. Department of Energy (2012 only), and accounting consultation in connection with due diligence (2011 only).

(c) Tax fees for 2012 relate to the review of permanent tax benefits associated with Medicare Part D subsidies. There were no tax fees for 2011.

(d) There were no all other fees for 2012 and 2011.

(e) Total fees reported above include out-of-pocket expenses related to the services provided of $332,210 for 2012 and $305,346 for 2011.

Pre-Approval Policy

The audit committee pre-approved all services Deloitte & Touche LLP performed in 2012 in accordance with the pre-approval policy and procedures the audit committee adopted at its August 12, 2003 meeting. This policy is designed to achieve the continued independence of Deloitte & Touche LLP and to assist in our compliance with Sections 201 and 202 of the Sarbanes-Oxley Act of 2002 and related rules of the Securities and Exchange Commission.

The policy defines the permitted services in each of the audit, audit-related, tax, and all other services categories, as well as prohibited services. The pre-approval policy requires management to submit annually for approval to the audit committee a service plan describing the scope of work and anticipated cost associated with each category of service. At each regular audit committee meeting, management reports on services performed by Deloitte & Touche LLP and the fees paid or accrued through the end of the quarter preceding the meeting. Management may submit requests for additional permitted services before the next scheduled audit committee meeting to the designated member of the audit committee, Dennis W. Johnson, for approval. The designated member updates the audit committee at the next regularly scheduled meeting regarding any services that he approved during the interim period. At each regular audit committee meeting, management may submit to the audit committee for approval a supplement to the service plan containing any request for additional permitted services.

In addition, prior to approving any request for audit-related, tax, or all other services of more than $50,000, Deloitte & Touche LLP will provide a statement setting forth the reasons why rendering of the proposed services does not compromise Deloitte & Touche LLP's independence. This description and statement by Deloitte & Touche LLP may be incorporated into the service plan or as an exhibit thereto or may be delivered in a separate written statement.

ITEM 3. APPROVAL, ON A NON-BINDING ADVISORY BASIS, OF THE COMPENSATION OF THE COMPANY'S NAMED EXECUTIVE OFFICERS

In accordance with Section 14A of the Securities Exchange Act of 1934 and Rule 14a-21(a), we are asking our stockholders to approve, in a separate advisory vote, the compensation of our named executive officers as disclosed in this proxy statement pursuant to Item 402 of Regulation S-K. As discussed in the compensation discussion and analysis, our compensation committee and board of directors believe that our current executive compensation program directly links compensation of our named executive officers to our financial performance and aligns the interests of our named executive officers with those of our stockholders. Our compensation committee and board of directors also believe that our executive compensation program provides our named executive officers with a balanced compensation package that includes an appropriate base salary along with competitive annual and long-term incentive compensation targets. These incentive programs are designed to reward our named executive officers on both an annual and long-term basis if they attain specified goals.

Our overall compensation program and philosophy is built on a foundation of these guiding principles:

- we pay for performance, with over 50% of our 2012 total target direct compensation in the form of incentive compensation
- we assess the relationship between our named executive officers' pay and performance on key financial metrics – revenue, profit, return on invested capital, and stockholder return – in comparison to our performance graph peer group
- we review competitive compensation data for our named executive officers, to the extent available, and incorporate internal equity in the final determination of target compensation levels
- we determine annual performance incentives based on financial criteria that are important to stockholder value, including earnings per share and return on invested capital and
- we determine long-term performance incentives based on total stockholder return relative to our performance graph peer group.

We are asking our stockholders to indicate their approval of our named executive officer compensation as disclosed in this proxy statement, including the compensation discussion and analysis, the executive compensation tables, and narrative discussion. This vote is not intended to address any specific item of compensation, but rather the overall compensation of our named executive officers for 2012. Accordingly, the following resolution is submitted for stockholder vote at the 2013 annual meeting:

> "RESOLVED, that the compensation paid to the company's named executive officers, as disclosed pursuant to Item 402 of Regulation S-K, including the Compensation Discussion and Analysis, compensation tables and narrative discussion, is hereby APPROVED."

As this is an advisory vote, the results will not be binding on the company, the board of directors, or the compensation committee and will not require us to take any action. The final decision on the compensation of our named executive officers remains with our compensation committee and our board of directors, although our board and compensation committee will consider the outcome of this vote when making future compensation decisions. As the board of directors determined at its meeting in May 2011, we will provide our stockholders with the opportunity to vote on our named executive officer compensation at every annual meeting until the next required vote on the frequency of stockholder votes on named executive officer compensation. The next required vote on frequency will occur at the 2017 annual meeting of stockholders.

The board of directors recommends a vote "for" the approval, on a non-binding advisory basis, of the compensation of our named executive officers, as disclosed in this proxy statement.

Approval of the compensation of our named executive officers requires the affirmative vote of a majority of our common stock present in person or represented by proxy at the meeting and entitled to vote on the proposal. Abstentions will count as votes against this proposal. Broker non-votes are not counted as voting power present and, therefore, are not counted in the vote.

EXECUTIVE COMPENSATION

Compensation Discussion and Analysis

The following compensation discussion and analysis may contain statements regarding corporate performance targets and goals. These targets and goals are disclosed in the limited context of our compensation programs and should not be understood to be statements of management's expectations or estimates of results or other guidance. We specifically caution investors not to apply these statements to other contexts.

Summary of Company Performance and Named Executive Officer Compensation – 2012 Compared to 2011

Our named executive officers for 2012 were:

- Terry D. Hildestad, our president and chief executive officer, who retired January 3, 2013
- Doran N. Schwartz, our vice president and chief financial officer
- William E. Schneider, our executive vice president of Bakken development, a role he assumed on January 1, 2012
- J. Kent Wells, who led our exploration and production segment as president and chief executive officer of Fidelity Exploration & Production Company, a direct wholly-owned subsidiary of WBI Holdings, Inc., and
- Steven L. Bietz, who led our pipeline and energy services segment as president and chief executive officer of WBI Holdings, Inc., which is the parent company of WBI Energy, Inc. and WBI Energy Services, Inc.

In addition to the business segments above, we have the following business segments:

- electric and natural gas distribution[1] under the leadership of David L. Goodin, who was during 2012 the president and chief executive officer of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company, and who was promoted, effective January 4, 2013, to be president and chief executive officer of MDU Resources Group, Inc., and
- construction services segment and construction materials and contracting segment under the leadership of John G. Harp, who is the chief executive officer of MDU Construction Services Group, Inc. and Knife River Corporation.

1 Natural gas distribution is a separate business segment, although we are showing it combined in this discussion.

Financial Results for 2012 and 2011

Our consolidated financial results for 2012 was a loss of $1.4 million compared to 2011 earnings of $212.3 million. Adjusted earnings were $216.8 million for 2012, compared to 2011 adjusted earnings of $225.2 million. The following table compares 2012 results to 2011 results on a business segment basis. Adjusted earnings and information in the table below contain non-GAAP numbers. Please refer to the Use of Non-GAAP Financial Measures and Reconciliation of GAAP to Adjusted Earnings sections below.

Business Segment	2012 Earnings ($) (millions)	2011 Earnings ($) (millions)
Electric and Natural Gas Distribution	60.0	67.6
Pipeline and Energy Services	11.6	23.1
Exploration and Production	69.6	80.3
Construction Materials and Services	70.8	48.0
Other	4.8	6.2
Earnings Before Discontinued Operations, Noncash Write-Downs of Oil and Natural Gas Properties, and Net Benefit Related to Natural Gas Gathering Operations Litigation	**216.8**	**225.2**
Income (Loss) from Discontinued Operations, Net of Tax*	13.6	(12.9)
Effects of Noncash Write-Downs of Oil and Natural Gas Properties	(246.8)	–
Net Benefit Related to Natural Gas Gathering Operations Litigation	15.0	–
Earnings (Loss) on Common Stock	(1.4)	212.3

* Reflects a 2012 reversal of a 2011 arbitration charge of $13.0 million after tax related to a guarantee of a construction contract

Use of Non-GAAP Financial Measures

As noted above, the company, in addition to presenting its earnings information in conformity with Generally Accepted Accounting Principles (GAAP), has provided non-GAAP earnings data that reflects an adjustment to exclude a fourth quarter 2012 $145.9 million after-tax noncash ceiling test write-down, a third quarter 2012 $100.9 million after-tax noncash ceiling test write-down, as well as an adjustment to exclude a second quarter 2012 reversal of an arbitration charge of $15.0 million after-tax. The company believes that these non-GAAP financial measures are useful to investors because the items excluded are not indicative of the company's continuing operating results. Also, the company's management uses these non-GAAP financial measures as indicators for planning and forecasting future periods. The presentation of this additional information is not meant to be considered a substitute for financial measures prepared in accordance with GAAP.

Reconciliation of GAAP to Adjusted Earnings

	2012 Earnings ($) (millions)	2011 Earnings ($) (millions)	2012 Earnings Per Share	2011 Earnings Per Share
Earnings (Loss) on Common Stock	(1.4)	212.3	(0.01)	1.12
Discontinued Operations	(13.6)	12.9	(0.07)	0.07
Noncash Write-Downs of Oil and Natural Gas Properties	246.8	–	1.31	–
Net Benefit Related to Natural Gas Gathering Operations Litigation	(15.0)	–	(0.08)	–
Adjusted Earnings	216.8	225.2	1.15	1.19

Total Realized Pay in 2012 and 2011

The compensation committee believes considering total realized pay is equally as important as considering total compensation as presented in the summary compensation table. Total compensation as presented in the summary compensation table contains estimated values of grants of performance shares based on multiple assumptions that may or may not come to fruition. Also, the summary compensation table shows an increase in change in pension value and above-market earnings on nonqualified deferred compensation. The pension plan was frozen as of December 31, 2009, and none of the named executives' benefit levels in the Supplemental Income Security Plan, our non-qualified retirement program, increased for 2012. The primary reason for increases in the change in pension value is due to a lower discount rate used to calculate the values.

Total realized pay, on the other hand, reflects the compensation actually earned, including the value of incentive awards if the goals are met and excluding the value of incentive awards if the goals are not met. Because we have not met certain performance measures in the last several years, our named executive officers' total realized pay excludes the value of incentive awards that were not earned. We define total realized pay as the sum of base salary, annual incentive award paid, the value realized upon the vesting of long-term incentive awards of performance shares, and all other compensation as reported in the summary compensation table.

The following table compares total realized pay for our named executives in 2012 to 2011.

Named Executive Officer	Year	Base Salary ($)	Annual Incentive Awards and Bonus Paid ($)	Value Realized upon Vesting of Performance Shares ($)	All Other Compensation ($)	Total Realized Pay ($)
Terry D. Hildestad	2012	750,000	518,250	0(1)	38,224	1,306,474
	2011	750,000	954,750	0(2)	37,499	1,742,249
Doran N. Schwartz	2012	300,000	103,650	0(1)	34,224	437,874
	2011	273,000	173,765	0(2)	33,549	480,314
Steven L. Bietz	2012	360,500	347,973	0(1)	37,884	746,357
	2011	360,500	229,198	0(2)	37,159	626,857
J. Kent Wells	2012	550,000	934,042(3)	N/A	96,470	1,580,512
	2011	367,671	1,923,991(4)	N/A	84,580	2,376,242
William E. Schneider	2012	447,400	200,950	0(1)	38,224	686,574
	2011	447,400	436,215	0(2)	37,499	921,114

(1) Performance shares and dividend equivalents granted for the 2009-2011 performance period that did not vest and were forfeited because performance was below threshold.

(2) Performance shares and dividend equivalents granted for the 2008-2010 performance period that did not vest and were forfeited because performance was below threshold.

(3) Reflects the value of the portion of Mr. Wells' additional 2011 annual incentive award that was paid in shares of our common stock based on our closing stock price of $21.67 on the vesting date, February 16, 2012.

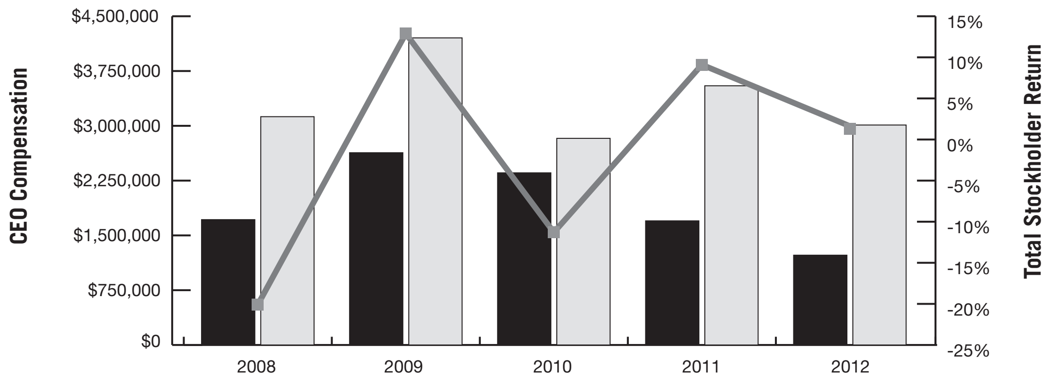
(4) Mr. Wells was hired as president and chief executive officer of Fidelity Exploration & Production Company effective May 2, 2011. Includes a cash recruitment payment of $550,000, annual incentive payment of $448,981, and additional annual incentive payment of $925,010.

Our named executive officers forfeited all performance shares and dividend equivalents for the 2009-2011 performance period because our total stockholder return in comparison to our peer group was at the 25th percentile. With respect to the annual incentive awards, our 2012 results in the construction services segment, construction materials and contracting segment, and the pipeline and energy services segment were above their performance targets, and, conversely, 2012 results for the exploration and production segment and the electric and gas distribution segments were below their threshold performance goals, with 2012 consolidated earnings per share results also below threshold. Since the corporate named executives' annual incentives depend on achievement of the foregoing performance goals, Messrs. Hildestad's, Schwartz's, and Schneider's 2012 annual incentives were paid below the target amount.

With respect to our chief executive officer, the following table further demonstrates our pay for performance approach by comparing:

- his total realized pay, which is the sum of base salary, annual incentive awards paid, all other compensation, and the value realized upon the
    - vesting of restricted stock during 2010
    - vesting of performance shares during 2008, 2009, and 2010 (none vested in 2011 or 2012)
- his total compensation as reported in the summary compensation table and
- one-year total stockholder returns for 2008 through 2012.

5 Year CEO Compensation and Total Stockholder Return



	2008	2009	2010	2011	2012
Total Realized Pay	$1,689,799	$2,657,250	$2,344,221	$1,742,249	$1,306,474
Total Compensation from Summary Compensation Table	$3,119,702	$4,203,004	$2,860,918	$3,566,327	$2,558,778
1 Year Total Stockholder Return	-20.1%	12.9%	-11.3%	9.1%	2.1%

The yearly changes in total compensation from the summary compensation table and total realized pay align very closely with the yearly changes in total stockholder return.

Overview of 2012 Compensation for our Named Executive Officers

In 2012, we continued our approach of referencing market data to establish competitive pay levels for base salary, total annual cash, which is base salary plus target annual incentive, and total direct compensation, which is the sum of total annual cash plus the expected value of target long-term incentives. We discuss this competitive assessment in the Role of Management section below. To ensure compensation awarded to named executive officers was commensurate with competitive performance levels, we continued to compare:

- total stockholder return results to the results of our performance graph peer group to determine payouts under our performance share program and
- on a historical basis, our targeted and actual results on return on invested capital to the results of our performance graph peer group when the compensation committee established performance targets for annual incentives of our business segment leaders.

Our overall compensation program and philosophy is built on a foundation of these guiding principles:

- we pay for performance, with 55.6% to 76.5% of our named executive officers' 2012 total target direct compensation in the form of incentives
- we determine annual performance incentives based on financial criteria that are important to stockholder value, including earnings per share and return on invested capital
- we determine long-term performance incentives based on total stockholder return relative to our performance graph peer group
- we review competitive compensation data for our named executive officers, to the extent available, and incorporate internal equity in the final determination of target compensation levels and
- through our PEER Analysis, we compare our pay-for-performance results on key financial metrics – revenue, profit, return on invested capital, and stockholder return – in comparison to our performance graph peer group.

The compensation committee took the following actions with respect to 2012 compensation for our named executive officers:

- granted a salary increase to Mr. Hildestad to recognize his effective leadership during an extended period of economic softness. Mr. Hildestad subsequently rejected the salary increase because he felt accepting the increase would be out of place since five of the thirteen Section 16 officers did not receive an increase for 2012
- granted a salary increase to Mr. Schwartz to bring his salary closer to his salary grade midpoint

- tied 25% of our business segment leaders' 2012 annual incentive targets to the company's 2012 earnings per share results in order to more closely align amounts paid to these executives with total company results
- increased Mr. Wells' annual incentive target from 100% to 125% of base salary to mitigate the impact of the added company earnings per share goal and to reflect his impact on overall company results
- continued to link our corporate executives' – i.e., Messrs. Hildestad, Schwartz, and Schneider – 2012 annual incentive awards to the achievement of our business segments' performance goals
- did not approve payment of any performance shares or dividend equivalents granted in 2009 for the 2009-2011 performance period due to our total stockholder return for the 2009-2011 performance period placing us in the 25th percentile compared to our performance graph peer group and
- granted no increases under our Supplemental Income Security Plan, which is a nonqualified retirement plan that provides benefits to our key managers and four of our named executive officers.

In addition, our Section 16 officers who had change of control employment agreements agreed to the early termination of their agreements, effective November 1, 2012.

Objectives of our Compensation Program

We structure our compensation program to help retain and reward the executive officers who we believe are critical to our long-term success. We have a written executive compensation policy for our Section 16 officers, including all our named executive officers. Our policy's stated objectives are to:

- recruit, motivate, reward, and retain high performing executive talent required to create superior long-term total stockholder return in comparison to our peer group
- reward executives for short-term performance, as well as the growth in enterprise value over the long-term
- provide a competitive package relative to industry-specific and general industry comparisons and internal equity, as appropriate
- ensure effective utilization and development of talent by working in concert with other management processes – for example, performance appraisal, succession planning, and management development and
- help ensure that compensation programs do not encourage or reward excessive or imprudent risk taking.

Elements of our Compensation Program

We pay/grant:

- base salaries in order to provide executive officers with sufficient, regularly-paid income and attract, recruit, and retain executives with the knowledge, skills, and abilities necessary to successfully execute their job duties and responsibilities
- opportunities to earn annual incentive compensation in order to be competitive from a total remuneration standpoint and ensure focus on annual financial and operating results and
- opportunities to earn long-term incentive compensation in order to be competitive from a total remuneration standpoint and ensure focus on stockholder return.

If earned, incentive compensation, which consists of annual cash incentive awards and three-year performance share awards under our Long-Term Performance-Based Incentive Plan, makes up the greatest portion of our named executive officers' total compensation. The compensation committee believes incentive compensation that comprised approximately 55.6% to 76.5% of total target compensation for the named executive officers is appropriate because:

- our named executive officers are in positions to drive, and therefore bear high levels of responsibility for, our corporate performance
- incentive compensation is more variable than base salary and dependent upon our performance
- variable compensation helps ensure focus on the goals that are aligned with our overall strategy and
- the interests of our named executive officers will be aligned with those of our stockholders by making a majority of the named executive officers' target compensation contingent upon results that are beneficial to stockholders.

The following table shows the allocation of total target compensation for 2012 among the individual components of base salary, annual incentive, and long-term incentive:

Name	% of Total Target Compensation Allocated to Base Salary (%)	% of Total Target Compensation Allocated to Incentives		
		Annual (%)	Long-Term (%)	Annual + Long-Term (%)
Terry D. Hildestad	28.6	28.6	42.8	71.4
Doran N. Schwartz	44.4	22.2	33.4	55.6
Steven L. Bietz	39.2	25.5	35.3	60.8
J. Kent Wells	23.5	29.4	47.1	76.5
William E. Schneider	39.2	25.5	35.3	60.8

In order to reward long-term growth, the compensation committee generally allocates a higher percentage of total target compensation to the long-term incentive than to the short-term incentive for our higher level executives, since they are in a better position to influence our long-term performance. Additionally, the long-term incentive, if earned, is paid in company common stock. These awards, combined with our stock retention requirements and stock ownership policy, promote ownership of our stock by the named executive officers. The compensation committee believes that, as stockholders, the named executive officers will be motivated to consistently deliver financial results that build wealth for all stockholders over the long-term.

Role of Management

Our executive compensation policy calls for an assessment of the competitive pay levels for base salary and incentive compensation for each Section 16 officer position to be conducted at least every two years by an independent consulting firm. Towers Watson conducted the study in 2010 for use by the compensation committee to determine 2011 compensation levels. In 2011, the compensation committee requested the competitive assessment be completed internally. They directed the vice president-human resources and the human resources department to prepare the competitive assessment in August 2011 on Section 16 officers for their use in establishing 2012 compensation.

The assessment included identifying any material changes to the positions analyzed, updating competitive compensation information, gathering and analyzing relevant general and industry-specific survey data, and updating the base salary structure. The human resources department assessed competitive pay levels for base salary, total annual cash, which is base salary plus target annual incentives, and total direct compensation, which is the sum of total annual cash and the expected value of target long-term incentives. The competitive assessment compared our positions to like positions contained in general industry compensation surveys and industry-specific compensation surveys. The human resources department aged the survey data from the date of the survey by 2.5% annualized to estimate the 2012 competitive targets.

The compensation surveys are listed on the following table:

Survey*	Number of Companies Participating (#)	Median Number of Employees (#)(1)	Number of Publicly-Traded Companies (#)	Median Revenue (000s) ($)
Towers Watson 2010 General Industry Executive Database	430	16,400	312	5,112,000
Towers Watson 2010 U.S. CDB Energy Services Executive Database	102	3,012	67	2,818,000
2010 Effective Compensation, Inc. Oil & Gas Exploration Compensation Survey	121	439	48	Not Reported
Mercer's 2010 Total Compensation Survey for the Energy Sector	297	Not Reported	201	823,000
Towers Watson 2010/2011 Report on Top Management Compensation	3,422	–(2)	–(2)	–(2)

(1) For the 2010 Effective Compensation, Inc. Oil & Gas Exploration Compensation Survey, the number reported as the Median Number of Employees is the average number of employees.

(2) The 3,422 organizations participating in Towers Watson's 2010/2011 Top Management Compensation Survey included 394 organizations with 2,000 to 4,999 employees; 308 organizations with 5,000 to 9,999 employees; 205 organizations with 10,000 to 19,999 employees; and 87 organizations with 20,000 or more employees. Towers Watson did not provide a revenue breakdown or the number of publicly-traded companies participating in its survey.

* The information in the table is based solely upon information provided by the publishers of the surveys and is not deemed filed or a part of this compensation discussion and analysis for certification purposes. For a list of companies that participated in the compensation surveys and databases, see Exhibit A.

In billions of dollars our revenues for 2010, 2011, and 2012 were approximately $3.9, $4.0, and $4.1, respectively.

The human resources department also augmented the competitive analysis by using Equilar to provide information on what was reported by companies in our performance graph peer group and by other public companies in relevant industries, as selected by the human resources department and as determined by SIC codes and as disclosed in their SEC filings. The companies referenced via Equilar and the positions for which they were used are found in Exhibit B.

For our president and chief executive officer, the Equilar companies included all companies in our performance graph peer group and data on 68 additional chief executive officers from public companies in the energy, construction, and utility industries with revenues ranging from $1 billion to $8 billion.

For our vice president and chief financial officer, the Equilar companies included all companies in our performance graph peer group and data on 55 additional chief financial officers from public companies in the energy, construction, and utility industries with revenues ranging from $1 billion to $8 billion.

For the president and chief executive officer of our exploration and production segment, the Equilar companies included the exploration and production companies in our performance graph peer group and data on 27 additional chief executive officers from public companies in the oil and gas exploration and production industries with revenues ranging from $250 million to $850 million.

For the president and chief executive officer of the pipeline and energy services segment, the Equilar companies included the pipeline and energy services companies in our performance graph peer group and data on 13 chief executive officers from public companies in the pipeline and energy services industry with revenues of $1 billion or less.

The chief executive officer played an important role in recommending 2012 compensation to the committee for the other named executive officers. The chief executive officer assessed the performance of the named executive officers and considered the relative value of the named executive officers' positions and their salary grade classifications. He then reviewed the competitive assessment prepared by the human resources department to formulate 2012 compensation recommendations for the compensation committee, other than for himself. The chief executive officer attended compensation committee meetings; however, he was not present during discussions regarding his compensation.

Timing of Compensation Decisions for 2012

The compensation committee, in conjunction with the board of directors, determined all compensation for each named executive officer for 2012 and set overall and individual compensation targets for the three components of compensation – base salary, annual incentive, and long-term incentive. The compensation committee made recommendations to the board of directors regarding compensation of all Section 16 officers, and the board of directors then approved the recommendations.

The compensation committee reviewed the competitive assessment and established 2012 salary grades at its August 2011 meeting. At the November 2011 meeting, it established individual base salaries, target annual incentive award levels, and target long-term incentive award levels for 2012. At their February and March 2012 meetings, the compensation committee and the board of directors increased the target annual incentive award level for Mr. Wells and determined annual and long-term incentive awards, along with the payouts based on performance from the recently completed performance period for prior annual and long-term awards. The February and March 2012 meetings occurred after the release of earnings for the prior year.

Stockholder Advisory Vote ("Say on Pay")

Our stockholders had their second advisory vote on our named executive officers' compensation at the 2012 Annual Meeting of Stockholders. Approximately 92% of the shares present in person or represented by proxy and entitled to vote on the matter approved the named executive officers' compensation. The 92% approval is consistent with the results of our say on pay vote at the 2011 Annual Meeting. The compensation committee and the board of directors considered the results of the votes at their November 2011 and November 2012 meetings and did not change our executive compensation program as a result of the votes.

Salary Grades for 2012

The compensation committee determines the named executive officers' base salaries and annual and long-term incentive targets by reference to salary grades. Each salary grade has a minimum, midpoint, and maximum annual salary level with the midpoint targeted at approximately the 50th percentile of the competitive assessment data for positions in the salary grade. The compensation committee may adjust the salary grades away from the 50th percentile in order to balance the external market data with internal equity. The salary grades also have annual and long-term incentive target levels, which are expressed as a percentage of the individual's actual base salary. We generally place named executive officers into a salary grade based on historical classification of their positions; however, the compensation committee reviews each classification and may place a position into a different salary grade if it determines that the targeted competitive compensation for the position changes significantly or the executive's responsibilities and/or performance warrants a different salary grade. Individual executives may be paid below, equal to, or above the salary grade midpoint. Mr. Wells' 2011 compensation was determined pursuant to his letter agreement in connection with his hiring effective May 2, 2011, and served as a basis for his 2012 compensation, rather than the business segment leaders' salary grade.

The salary grades give the compensation committee flexibility to assign different salaries to individual executives within a salary grade to reflect one or more of the following:

- executive's performance on financial goals and on non-financial goals, including the results of the performance assessment program
- executive's experience, tenure, and future potential
- position's relative value compared to other positions within the company
- relationship of the salary to the competitive salary market value
- internal equity with other executives and
- economic environment of the corporation or executive's business segment.

No changes were made in the salary grade classifications of the named executive officers for 2012, and after reviewing the competitive analysis, the compensation committee made no changes in the base salary ranges associated with each named executive officer's salary grade classification.

Our named executive officers' salary grade classifications for 2012 are listed below, along with the base salary ranges associated with each classification:

			2012 Base Salary (000s)		
Position	Grade	Name	Minimum ($)	Midpoint ($)	Maximum ($)
President and CEO	K	Terry D. Hildestad	620	775	930
Vice President and CFO	I	Doran N. Schwartz	260	325	390
President and CEO, WBI Holdings, Inc.	J	Steven L. Bietz	312	390	468
President and CEO, Fidelity Exploration & Production Company	J	J. Kent Wells	312	390	468
Executive Vice President – Bakken Development	J	William E. Schneider	312	390	468

Performance Assessment Program

Our performance assessment program rates performance of our executive officers, except for our chief executive officer, in the following areas, which help determine actual salaries within the range of salaries associated with the executive's salary grade:

- visionary leadership
- strategic thinking
- leading with integrity
- managing customer focus
- financial responsibility
- achievement focus
- judgment
- planning and organization
- leadership
- mentoring
- relationship building
- conflict resolution
- organizational savvy
- safety
- risk management

An executive's overall performance in our performance assessment program is rated on a scale of one to five, with five as the highest rating denoting distinguished performance. An overall performance above 3.75 is considered commendable performance.

The chief executive officer assessed each other named executive officer's performance under the performance assessment program, and the compensation committee, as well as the full board of directors, assessed the chief executive officer's performance.

The board of directors rates our chief executive officer's performance in the following areas:

- leadership
- integrity and values
- strategic planning
- financial results
- communications
- succession planning
- human resources
- external relations
- board relations
- risk management

Our chief executive officer's performance was rated on a scale of one to five, with five as the highest rating denoting performance well above expectations.

Base Salaries of the Named Executive Officers for 2012

Terry D. Hildestad
The compensation committee recommended a 6.67% salary increase for Mr. Hildestad for 2012, which would have raised his salary from $750,000 to $800,000 ($775,000 being the market median). The compensation committee's rationale for the increase was

- his high performance evaluation
- his high integrity, excellent business know how, and ability to work effectively with the management team and the board
- his effectiveness in navigating the company through a difficult economic environment and
- his salary had been frozen since January 1, 2009.

Mr. Hildestad, however, did not accept his base salary increase for 2012 in order to be treated the same as other Section 16 officers who did not receive a salary increase for 2012.

Doran N. Schwartz
Mr. Schwartz was elected vice president and chief financial officer effective February 17, 2010. For 2012, the compensation committee awarded Mr. Schwartz a 9.9% increase, raising his 2012 salary from $273,000 to $300,000, or 92% of the midpoint of salary grade I for 2012. The compensation committee's rationale for the increase was in recognition of:

- his assistance in the company achieving a return on invested capital of 6.9% for the twelve months ending June 2011 as compared to the median return on invested capital of 6.0% for companies in our performance graph peer group over the same time period
- his success at building good working relationships with shareholders, rating agencies, and the financial community and
- moving his salary closer to the midpoint of salary grade I.

Steven L. Bietz
Mr. Bietz received no salary increase for 2012 because the compensation committee wanted to limit salary cost increases.

J. Kent Wells
Mr. Wells received no salary increase for 2012 because he had just started his employment with the company in May 2011 with a salary above the maximum for his salary grade.

William E. Schneider
Mr. Schneider received no salary increase for 2012 because his salary was 115% of the market value for his position and the compensation committee wanted to limit salary cost increases.

2012 Annual Incentives

What the Performance Measures Are and Why We Chose Them
The compensation committee develops and reviews financial and other corporate performance measures to help ensure that compensation to the executives reflects the success of their respective business segment and/or the corporation, as well as the value provided to our stockholders. For all business segment chief executive officers, including Messrs. Wells and Bietz, the performance measures for annual incentive awards are

- their respective business segment's annual return on invested capital results compared to target
- their respective business segment's allocated earnings per share results compared to target and
- the company's consolidated earnings per share compared to a target of $1.19.

The compensation committee added the third performance measure, consolidated earnings per share, for the first time in 2012. The compensation committee weighted the 2012 performance measures for Messrs. Wells and Bietz at 75% for their business segment performance measures (weighted evenly) and 25% for the company's earnings per share measure to more closely tie their annual incentive amounts to total company results.

For the named executive officers working at MDU Resources Group, Inc. in 2012, who were Messrs. Hildestad, Schwartz, and Schneider, the compensation committee based 2012 annual incentives on the achievement of performance goals at the business segments: (i) the construction materials and contracting and construction services segments, (ii) the pipeline and energy services segment, (iii) the exploration and production segment, and (iv) the electric and natural gas distribution segments. The compensation committee's rationale for this approach was to provide greater alignment between the MDU Resources Group, Inc. executives and business segment performance.

The compensation committee believes earnings per share and return on invested capital are very good measurements in assessing a business segment's performance and the company's performance from a financial perspective. Earnings per share is a generally accepted accounting principle measurement and is a key driver of stockholder return over the long-term. Return on invested capital measures how efficiently and effectively management deploys capital. Sustained returns on invested capital in excess of a business segment's cost of capital create value for our stockholders.

Allocated earnings per share for a business segment is calculated by dividing that business segment's earnings by the business segment's portion of the total company weighted average shares outstanding. Return on invested capital for a business segment is calculated by dividing the business segment's earnings, without regard to after tax interest expense and preferred stock dividends, by the business segment's average capitalization for the calendar year.

We establish our incentive plan performance targets in connection with our annual financial planning process, where we assess the economic environment, competitive outlook, industry trends, and company specific conditions to set projections of results. The compensation committee evaluates the projected results and uses this evaluation to establish the incentive plan performance targets based upon recommendation of the chief executive officer. In determining where to set the return on invested capital target, the compensation committee considers the business segment's weighted average cost of capital. The weighted average cost of capital is a composite cost of the individual sources of funds including equity and debt used to finance a company's assets. It is calculated by averaging the cost of debt plus the cost of equity by the proportion each represents in our, or the business segment's, capital structure. For 2012, the compensation committee chose to use the return on invested capital target for each business segment as approved by the board in the 2012 business plan, except for the construction services segment, which had a target higher than the 2012 business plan to incentivize efforts for that segment to achieve its weighted average cost of capital within five years. The compensation committee imposed an additional requirement for the 2012 return on invested capital portion of the annual incentives for the construction materials and contracting segment, the construction services segment, and the exploration and production segment. The additional requirement was the business segment needed to achieve its weighted average cost of capital in order to achieve 200% of the annual incentive target attributable to the return on invested capital portion of the annual incentive. However, payments with respect to 2012 return on invested capital results above the 2012 target but below the weighted average cost of capital would be interpolated, in order to motivate these executives to achieve performance levels between the return on invested capital performance targets and the weighted average cost of capital for their respective business segments.

Named Executive Officers' 2012 Incentive Targets and Why We Chose Them

Targets
The compensation committee established the named executive officers' annual incentive targets as a percentage of each officer's actual 2012 base salary.

Messrs. Hildestad's, Schwartz's, and Schneider's 2012 target annual incentives were 100%, 50%, and 65% of base salary, respectively. The compensation committee determined the 2012 annual incentive targets would remain unchanged from 2011 for these named executives based on the following reasons:

- For Mr. Hildestad, the annual incentive target of 100% of base salary was slightly above the 86% of base salary paid to chief executive officer positions based on salary survey data from the competitive assessment. The committee believed this difference was too small to warrant a change in Mr. Hildestad's 2012 incentive target.
- For Mr. Schwartz, the annual incentive target of 50% of base salary was slightly below 57% of base salary paid to chief financial officers based on salary survey data from the competitive assessment. The committee believed this difference was too small to warrant a change in Mr. Schwartz's 2012 incentive target.
- For Mr. Schneider, the compensation committee determined his 2012 incentive target should remain the same from 2011 because of the importance the company placed on his new role of leveraging opportunities in the Bakken that would cut across all of the company's business segments. There was no competitive data compiled on his position.

Mr. Bietz's 2012 target annual incentive was 65% of base salary. The compensation committee determined the 2012 annual incentive target would remain unchanged from 2011 for Mr. Bietz because the annual incentive based on salary survey data from the competitive assessment was 62% of base salary. The committee believed this difference was too small to warrant a change in Mr. Bietz's 2012 target annual incentive.

Mr. Wells' 2012 incentive target was 125% of base salary, which was increased from 100% of base salary. The committee raised Mr. Wells' annual incentive target to mitigate the impact of the added company earnings per share goal and to reflect his business segment's impact on overall company results. The committee recognized the significant investment that his business segment will make and the desire to incentivize and motivate Mr. Wells to generate earnings that can greatly impact overall company earnings.

Named Executive Officers' 2012 Incentive Payments

Terry D. Hildestad, Doran N. Schwartz, and William E. Schneider
As discussed above, Messrs. Hildestad, Schwartz, and Schneider were awarded 2012 incentives based on achievement of performance goals at the business segments. The award opportunities and results for the business segments are discussed below.

As a result of the performance goals achieved at the business segments, Messrs. Hildestad, Schwartz, and Schneider earned 69.1% of their target awards, resulting in a payment of $518,250 for Mr. Hildestad, $103,650 for Mr. Schwartz, and $200,950 for Mr. Schneider.

Pipeline and Energy Services Segment
For the pipeline and energy services segment, the 2012 award opportunity was comprised of three components:

- The pipeline and energy services segment component represented 75% of the target award, and payout could range from no payment if the results were below the 85% level to a 200% payout if:
  - the 2012 allocated earnings per share for the segment were at or above the 115% level and
  - the 2012 return on invested capital was at or above the 115% level.
- The MDU Resources Group, Inc. earnings per share component represented 25% of the award and payout could range from no payment if the results were below the $1.19 to a 200% payout if the results were $1.37 or higher.
- The pipeline and energy services segment also had five individual goals relating to safety results with each goal that was not met reducing the annual incentive award by 1%. The five individual goals were:
  - each established local safety committee will conduct eight meetings per year
  - each established local safety committee must conduct four site assessments per year
  - report vehicle accidents and personal injuries by the end of the next business day
  - achieve the targeted vehicle accident incident rate of 2.25 or less and
  - achieve the targeted personal injury incident rate of 2.0 or less.

The committee set the pipeline and energy services segment's 2012 allocated earnings per share and return on invested capital below the 2011 target levels and below the 2011 actual results. The 2012 target levels were based on lower natural gas prices and, as a result, lower storage and gas transmission activity.

The committee set the MDU Resources Group, Inc. earnings per share target at $1.19 because it was equal to the 2011 result, and the committee believed tying 25% of the incentive award to delivering at least $1.19 in 2012 was appropriate.

The pipeline and energy services segment's 2012 earnings per share and return on invested capital were 179.8% and 143.1% of their respective 2012 targets, equating to 200% of the target amount attributable to that component. Also, MDU Resources Group, Inc.'s 2012 earnings per share results were $(.01), equating to 0% of the target amount attributable to that component.

Results at the pipeline and energy services segment (before adjustment for the five safety goals) were 150% of the 2012 target annual incentive. One of the five safety goals was not met because WBI Energy's personal injury incident rate was 2.67. Therefore, the incentive results were reduced from 150% to 148.5% of the 2012 target annual incentive.

Exploration and Production Segment
For the exploration and production segment, the 2012 award opportunity was comprised of two components:

- The exploration and production business segment component represented 75% of the target award, and payout could range from no payment if the results were below the 85% level to a 200% payout if:
  - the 2012 allocated earnings per share for the segment were at or above the 115% level and
  - the 2012 return on invested capital was at least equal to the segment's 2012 weighted average cost of capital.
- The MDU Resources Group, Inc. earnings per share component represented 25% of the award and payout could range from no payment if the results were below the $1.19 target to a 200% payout if the results were $1.37 or higher.

The committee set the exploration and production segment's 2012 allocated earnings per share and return on invested capital target levels below the 2011 actual results. The 2012 allocated earnings per share target level was above the 2011 target level, and the 2012 return on invested capital target level was below the 2011 target level. The 2012 target levels were based on lower natural gas prices and higher depletion, depreciation, and amortization amounts. The committee set the MDU Resources Group, Inc. earnings per share target at $1.19 because it was equal to the 2011 result, and the committee believed tying 25% of the incentive award to delivering at least $1.19 in 2012 was appropriate.

This segment's 2012 earnings per share and return on invested capital were negative equating to no payment on either component. Also, MDU Resources Group, Inc.'s 2012 earnings per share results were $(.01), equating to 0% of the target amount attributable to that component.

Overall results for 2012 were 0%.

Construction Services and Construction Materials and Contracting Segments
For purposes of determining the annual incentive awards of the MDU Resources Group, Inc. executives and the chief executive officer of these segments, these segments were combined. The 2012 award opportunity was comprised of three components:

- The construction services segment component represented 37.5% of the target award, and payout could range from no payment if the results were below the 85% level to a 200% payout if:
  - the 2012 allocated earnings per share for the segment were at or above the 115% level and
  - the 2012 return on invested capital was at least equal to the segment's 2012 weighted average cost of capital.
- The construction materials and contracting segment component represented 37.5% of the award, and payment could range from no payment if the results were below the 85% level to a 200% payout if:
  - the 2012 allocated earnings per share for the segment were at or above the 115% level and
  - the 2012 return on invested capital was at least equal to the segment's 2012 weighted average cost of capital.
- The MDU Resources Group, Inc. earnings per share component represented 25% of the award and payout could range from no payment if the results were below the $1.19 target to a 200% payout if the results were $1.37 or higher.

The committee set the construction services business segment's 2012 allocated earnings per share and return on invested capital target levels above the 2011 target levels and below the 2011 actual results. The construction materials and contracting business segment's 2012 allocated earnings per share target level was set below the 2011 target level and 2011 actual results, and the 2012 return on invested capital target level was set above the 2011 target level and equal to the 2011 actual results. The 2012 target levels reflected significant uncertainty in the overall construction market, including an absence of a federal highway bill and continued low margins due to competitive bids on construction projects. The committee set the MDU Resources Group, Inc. earnings per share target at $1.19 because it was equal to the 2011 result, and the committee believed tying 25% of the incentive award to delivering at least $1.19 in 2012 was appropriate.

The construction services segment's 2012 earnings per share and return on invested capital were 226.6% and 205.4% of their respective 2012 targets, equating to 200% of the target amount attributable to that component. The construction materials and contracting segment's 2012 earnings per share and return on invested capital were 158.1% and 117.1% of their respective 2012 targets, equating to 155.9% of the target amount attributable to that component. MDU Resources Group, Inc.'s 2012 earnings per share results were $(.01), equating to 0% of the target amount attributable to that component.

Overall results for 2012 were 133.5% of the 2012 target annual incentive award.

Electric and Natural Gas Distribution Segments

For the electric and natural gas distribution segments, the 2012 award opportunity was comprised of two components:

- the electric and natural gas distribution business segments component represented 75% of the target award, and payout could range from no payment if the allocated earnings per share and return on invested capital results were below the 85% level to a 200% payout if:
    - the 2012 allocated earnings per share for the segment were at or above the 115% level and
    - the 2012 return on invested capital was at or above the 115% level.
- The MDU Resources Group, Inc. earnings per share component represented 25% of the award and payout could range from no payment if the results were below the $1.19 target to a 200% payout if the results were $1.37 or higher.

The committee set the 2012 target for allocated earnings per share higher than the 2011 targets but lower than 2011 actual results to reflect a one-time income tax benefit in 2011. The committee set the 2012 return on invested capital target at the 2011 target level, which was below 2011 actual results to reflect a one-time income tax benefit in 2011. For 2012, the electric and natural gas distribution segments' 2012 earnings per share and return on invested capital were 93.1% and 93.6% of their respective targets, equating to 66.7% of the target amount attributable to that component. MDU Resources Group, Inc.'s 2012 earnings per share results were $(.01), equating to 0% of the target amount attributable to that component.

Overall results for these segments were 50% of the 2012 target annual incentive award.

The following table shows the changes in our performance targets and achievements for both 2011 and 2012:

	2011 Incentive Plan Performance Targets		2011 Incentive Plan Results		2012 Incentive Plan Performance Targets			2012 Incentive Plan Results		
Name	EPS ($)	ROIC (%)	EPS ($)	ROIC (%)	EPS Business Segment ($)	ROIC (%)	EPS MDU Resources ($)	EPS Business Segment ($) / (% of Target)	ROIC (%) / (% of Target)	EPS MDU Resources ($) / (% of Target)
Pipeline and Energy Services	1.97	7.9	1.96	7.9	0.99	5.8	1.19	1.78 / 200	8.3 / 200	(.01) / 0
Exploration and Production	1.99	7.1	2.20	7.9	2.10	6.9	1.19	(4.81) / 0	(13.9) / 0	(.01) / 0
Construction Services	2.39	6.0	4.46	9.6	3.61	7.4	1.19	8.18 / 200	15.2 / 200	(.01) / 0
Construction Materials and Contracting	0.35	3.2	0.40	3.5	0.31	3.5	1.19	0.49 / 200	4.1 / 111.8	(.01) / 0
Electric and Natural Gas Distribution	1.14	6.2	1.21	6.5	1.16	6.2	1.19	1.08 / 65.5	5.8 / 67.8	(.01) / 0

PROXY

The table below lists each named executive officer's 2012 base salary, annual incentive target percentage, and the annual incentive earned.

Name	2012 Base Salary (000s) ($)	2012 Annual Incentive Target (%)	2012 Annual Incentive Earned (% of Target)	2012 Annual Incentive Earned (000s) ($)
Terry D. Hildestad	750.0	100	69.1	518.3
Doran N. Schwartz	300.0	50	69.1	103.7
Steven L. Bietz	360.5	65	148.5	348.0
J. Kent Wells	550.0	125	0.0	0.0
William E. Schneider	447.4	65	69.1	201.0

Messrs. Hildestad's, Schwartz's, and Schneider's 2012 annual incentives were paid at 69.1% of target based on the following:

	Column A Percentage of Annual Incentive Target Achieved	Column B Percentage of Average Invested Capital	Column A x Column B
Construction Services Segment and Construction Materials and Contracting Segment	133.5%	29.2%	39.0%
Exploration and Production Segment	0.0%	28.1%	0.0%
Pipeline and Energy Services Segment	148.5%	8.8%	13.1%
Electric and Natural Gas Distribution Segments	50.0%	33.9%	17.0%
Total (Payout Percentage)			69.1%

Deferral of Annual Incentive Compensation

We provide executives the opportunity to defer receipt of earned annual incentives. If an executive chooses to defer his or her annual incentive, we will credit the deferral with interest at a rate determined by the compensation committee. For 2012, the committee chose to use the average of (i) the number that results from adding the daily Moody's U.S. Long-Term Corporate Bond Yield Average for "A" rated companies as of the last day of each month for the 12-month period ending October 31 and dividing by 12 and (ii) the number that results from adding the daily Moody's U.S. Long-Term Corporate Bond Yield Average for "BBB" rated companies as of the last day of each month for the 12-month period ending October 31 and dividing by 12. This resulted in an interest rate of 5.46%. The compensation committee's reasons for using this approach recognized:

- incentive deferrals are a low-cost source of capital for the company and
- incentive deferrals are unsecured obligations and, therefore, carry a higher risk to the executives.

2012 Long-Term Incentives

Awards Granted in 2012 under the Long-Term Performance-Based Incentive Plan for Named Executives

We use the Long-Term Performance-Based Incentive Plan, which has been approved by our stockholders, for long-term incentive compensation. We use performance shares as the primary form of long-term incentive compensation. We have not granted stock options since 2001, and in 2011 we amended the plan to no longer permit the grant of stock options or stock appreciation rights; no stock options, stock appreciation rights, or restricted shares are outstanding.

The compensation committee used the performance graph peer group as the comparator group to determine relative stockholder return and potential payments for the 2012 performance share awards. The performance graph peer group consisted of the following companies when the committee granted performance shares in February 2012:

- Alliant Energy Corporation
- Atmos Energy
- Berry Petroleum Company
- Black Hills Corporation
- Comstock Resources, Inc.
- EMCOR Group, Inc.
- EQT Corporation
- Granite Construction Incorporated
- Martin Marietta Materials, Inc.
- National Fuel Gas Company
- Northwest Natural Gas Company
- Pike Electric Corporation
- Quanta Services, Inc.
- Questar Corporation
- SCANA Corporation
- Southern Union Company
- Southwest Gas Corporation
- Sterling Construction Company
- SM Energy Company
- Swift Energy Company
- Texas Industries
- Vectren Corporation
- Vulcan Materials Company
- Whiting Petroleum Corporation

The performance measure is our total stockholder return over a three-year measurement period as compared to the total stockholder returns of the companies in our performance graph peer group over the same three-year period. The compensation committee selected the relative stockholder return performance measure because it believes executive pay under a long-term, capital accumulation program such as this should mirror our long-term performance in stockholder return as compared to other public companies in our industries. Payments are made in company stock; dividend equivalents are paid in cash. No dividend equivalents are paid on unvested performance shares.

Total stockholder return is the percentage change in the value of an investment in the common stock of a company, from the closing price on the last trading day in the calendar year preceding the beginning of the performance period, through the last trading day in the final year of the performance period. It is assumed that dividends are reinvested in additional shares of common stock at the frequency paid.

As with the annual incentive target, we determined the long-term incentive target for a given position in part from the competitive assessment and in part by the compensation committee's judgment on the impact each position has on our total stockholder return. From an internal equity standpoint, the committee believed positions in the same salary grade should have the same long-term incentive target level. From an internal equity standpoint, the committee believed in keeping the chief executive officer's long-term incentive target below a level indicated from the competitive assessment. Mr. Hildestad's target was 150% of base salary, below the salary survey median of 231% of base salary for chief executive officers. The compensation committee has historically set Mr. Hildestad's target long-term incentive compensation below the level indicated by the competitive assessment to offset his benefit under the Supplemental Income Security Plan, our nonqualified defined benefit plan, which prior assessments have shown to be higher than competitive levels. The 2012 long-term incentive targets as a percentage of base salary for Messrs. Schwartz, Bietz, and Schneider were unchanged from 2011 because the targets were in line with the competitive assessment's targets. Mr. Wells' long-term incentive target is 200% of base salary, which is higher than the 90% long-term incentive target for other executives in salary grade J. The higher target for Mr. Wells was pursuant to his letter agreement and reflects the committee's judgment of offsetting Mr. Wells' non-participation in our Supplemental Income Security Plan.

On February 16, 2012, the board of directors, upon recommendation of the compensation committee, made performance share grants to the named executive officers. The compensation committee determined the target number of performance shares granted to each named executive officer by multiplying the named executive officer's 2012 base salary by his or her long-term incentive target and then dividing this product by the average of the closing prices of our stock from January 1, 2012 through January 22, 2012, as shown in the following table:

Name	2012 Base Salary to Determine Target ($)	2012 Long-Term Incentive Target at Time of Grant (%)	2012 Long-Term Incentive Target at Time of Grant ($)	Average Closing Price of Our Stock From January 1 Through January 22 ($)	Resulting Number of Performance Shares Granted on February 16 (#)
Terry D. Hildestad	750,000	150	1,125,000	21.54	52,228
Doran N. Schwartz	300,000	75	225,000	21.54	10,445
Steven L. Bietz	360,500	90	324,450	21.54	15,062
J. Kent Wells	550,000	200	1,100,000	21.54	51,067
William E. Schneider	447,400	90	402,660	21.54	18,693

Assuming our three-year (2012 to 2014) total stockholder return is positive, from 0% to 200% of the target grant will be paid out in February 2015 depending on our total stockholder return compared to the total three-year stockholder returns of companies in our performance graph peer group. The payout percentage will be a function of our rank against our performance graph peer group as follows:

Long-Term Incentive Payout Percentages

The Company's Percentile Rank	Payout Percentage of February 16, 2012 Grant
90th or higher	200%
70th	150%
50th	100%
40th	10%
Less than 40th	0%

Payouts for percentile ranks falling between the intervals will be interpolated. We also will pay dividend equivalents in cash on the number of shares actually earned for the performance period. The dividend equivalents will be paid in 2015 at the same time as the performance awards are paid.

If our total stockholder return is negative, the shares and dividend equivalents otherwise earned, if any, will be reduced in accordance with the following table:

TSR	Reduction in Award
0% through -5%	50%
-5.01% through -10%	60%
-10.01% through -15%	70%
-15.01% through -20%	80%
-20.01% through -25%	90%
-25.01% or below	100%

The named executive officers must retain 50% of the net after-tax shares that are earned pursuant to this long-term incentive award until the earlier of (i) the end of the two-year period commencing on the date any shares earned under the award are issued and (ii) the executive's termination of employment.

No Payment in February 2012 for 2009 Grants under the Long-Term Performance-Based Incentive Plan

We granted performance shares to our named executive officers under the Long-Term Performance-Based Incentive Plan on February 12, 2009 for the 2009 through 2011 performance period. Our total stockholder return for the 2009 through 2011 performance period was 9.25%, which corresponded to a percentile rank of 25% against our performance graph peer group and resulted in no shares or dividend equivalents being paid to the named executive officers.

PEER Analysis: Comparison of Pay for Performance Ratios

Each year we compare our named executive officers' pay for performance ratios to the pay for performance ratios of the named executive officers in the performance graph peer group. This analysis compares the relationship between our compensation levels and our average annual total stockholder return to the peer group over a five-year period. All data used in the analysis, including the valuation of long-term incentives and calculation of stockholder return, were compiled by Equilar, Inc., an independent service provider, which is based on each company's annual filings for its data collection.

This analysis consisted of dividing what we paid our named executive officers for the years 2007 through 2011 by our average annual total stockholder return for the same five-year period to yield our pay ratio. Our pay ratio was then compared to the pay ratio of the companies in the performance graph peer group, which was calculated by dividing total direct compensation for all the proxy group executives by the sum of each company's average annual total stockholder return for the same five-year period.

For the five-year period of 2007 through 2011, our average annual stockholder return was minus .88%. Therefore, our pay ratio is not a meaningful statistic and a comparison to the pay ratio of the companies in the performance graph peer group could not be made. The compensation committee believes that the analysis continues to serve a useful purpose in its annual review of compensation despite the effect of the negative stockholder return for the 2007 through 2011 period.

Post-Termination Compensation and Benefits

Pension Plans

Effective in 2006, we no longer offer defined benefit pension plans to new non-bargaining unit employees. The defined benefit plans available to employees hired before 2006 were amended to cease benefit accruals as of December 31, 2009. The frozen benefit provided through our qualified defined benefit pension plans is determined by years of service and base salary. Effective 2010, for those employees who were participants in defined benefit pension plans and for executives and other non-bargaining unit employees hired after 2006, the company offers increased company contributions to our 401(k) plan. For non-bargaining unit employees hired after 2006, the retirement contribution is 5% of plan eligible compensation. For participants hired prior to 2006, retirement contributions are based on the participant's age as of December 31, 2009. The retirement contribution is 11.5% for each of the named executive officers, except Mr. Schwartz who is eligible for 10.5% and Mr. Wells who is eligible for 5%.

Supplemental Income Security Plan

Benefits Offered

We offer certain key managers and executives, including all of our named executive officers, except Mr. Wells, benefits under our nonqualified retirement plan, which we refer to as the Supplemental Income Security Plan or SISP. The SISP has a ten-year vesting schedule and was amended to add an additional vesting requirement for benefit level increases occurring on or after January 1, 2010. The SISP provides participants with additional retirement income and death benefits.

We believe the SISP is critical in retaining the talent necessary to drive long-term stockholder value. In addition, we believe that the ten-year vesting provision of the SISP, augmented by an additional three years of vesting for benefit level increases occurring on or after January 1, 2010, helps promote retention of key executive officers.

Benefit Levels

The chief executive officer recommends benefit level increases to the compensation committee for participants except himself. The chief executive officer considers, among other things, the participant's salary in relation to the salary ranges that correspond with the SISP benefit levels, the participant's performance, the performance of the applicable business segment or the company, and the cost associated with the benefit level increase.

The chief executive officer did not recommend a 2012 SISP benefit level increase for any of the named executive officers, and the committee chose not to grant a 2012 SISP benefit level increase to the chief executive officer. The following table reflects our named executive officers' SISP levels as of December 31, 2012:

	December 31, 2012 Annual SISP Benefits	
Name	Survivor ($)	Retirement ($)
Terry D. Hildestad	1,025,040	512,520
Doran N. Schwartz	175,200	87,600
Steven L. Bietz	386,640	193,320
J. Kent Wells	N/A	N/A
William E. Schneider	548,400	274,200

Clawback

In November 2005, we implemented a guideline for repayment of incentives due to accounting restatements, commonly referred to as a clawback policy, whereby the compensation committee may seek repayment of annual and long-term incentives paid to executives if accounting restatements occur within three years after the payment of incentives under the annual and long-term plans. Under our clawback policy, the compensation committee may require executives to forfeit awards and may rescind vesting, or the acceleration of vesting, of an award.

Impact of Tax and Accounting Treatment

The compensation committee may consider the impact of tax and/or accounting treatment in determining compensation. Section 162(m) of the Internal Revenue Code places a limit of $1 million on the amount of compensation paid to certain officers that we may deduct as a business expense in any tax year unless, among other things, the compensation qualifies as performance-based compensation, as that term is used in Section 162(m). Generally, long-term incentive compensation and annual incentive awards for our chief executive officer and those executive officers whose overall compensation is likely to exceed $1 million are structured to be deductible for purposes of Section 162(m) of the Internal Revenue Code, but we may pay compensation to an executive officer that is not deductible. All annual or long-term incentive compensation paid to our named executive officers in 2012 satisfied the requirements for deductibility, except for $48,129 paid to Mr. Wells.

Section 409A of the Internal Revenue Code imposes additional income taxes on executive officers for certain types of deferred compensation if the deferral does not comply with Section 409A. We have amended our compensation plans and arrangements affected by Section 409A with the objective of not triggering any additional income taxes under Section 409A.

Section 4999 of the Internal Revenue Code imposes an excise tax on payments to executives and others of amounts that are considered to be related to a change of control if they exceed levels specified in Section 280G of the Internal Revenue Code. To the extent a change in control triggers liability for an excise tax, payment of the excise tax will be made by the individual. The company will not pay the excise tax. We do not consider the potential impact of Section 4999 or 280G when designing our compensation programs.

The compensation committee also considers the accounting and cash flow implications of various forms of executive compensation. In our financial statements, we record salaries and annual incentive compensation as expenses in the amount paid, or to be paid, to the named executive officers. For our equity awards, accounting rules also require that we record an expense in our financial statements. We calculate the accounting expense of equity awards to employees in accordance with Financial Accounting Standards Board generally accepted accounting principles for stock-based compensation.

Stock Ownership Requirements

We instituted stock ownership guidelines on May 5, 1993, which we revised in November 2010 to provide that executives who participate in our Long-Term Performance-Based Incentive Plan are required within five years to own our common stock equal to a multiple of their base salaries. Stock owned through our 401(k) plan or by a spouse is considered in ownership calculations. Unvested performance shares and other unvested equity awards are not considered in ownership calculations. The level of stock ownership compared to the requirements is determined based on the closing sale price of the stock on the last trading day of the year and base salary at December 31 of each year. Each February, the compensation committee receives a report on the status of stock holdings by executives. The committee may, in its sole discretion, grant an extension of time to meet the ownership requirements or take such other action as it deems appropriate to enable the executive to achieve compliance with the policy. The table shows the named executive officers' holdings as of December 31, 2012:

Name	Assigned Guideline Multiple of Base Salary	Actual Holdings as a Multiple of Base Salary	Number of Years at Guideline Multiple (#)
Terry D. Hildestad	4X	6.06	7.67
Doran N. Schwartz	3X	1.75	2.87(1)
Steven L. Bietz	3X	4.09	10.33
J. Kent Wells	3X	1.07	1.67(2)
William E. Schneider	3X	4.96	11.00

(1) Participant must meet ownership requirement by January 1, 2015.

(2) Participant must meet ownership requirement by May 1, 2016.

The compensation committee may consider the policy and the executive's stock ownership in determining compensation. The committee, however, did not do so with respect to 2012 compensation.

Policy Regarding Hedging Stock Ownership

Our executive compensation policy prohibits Section 16 officers from hedging their ownership of company common stock. Executives may not enter into transactions that allow the executive to benefit from devaluation of our stock or otherwise own stock technically but without the full benefits and risks of such ownership. See the Security Ownership section of the proxy statement for our policy on margin accounts and pledging of our stock.

Compensation Committee Report

The compensation committee has reviewed and discussed the Compensation Discussion and Analysis required by Regulation S-K, Item 402(b), with management. Based on the review and discussions referred to in the preceding sentence, the compensation committee recommended to the board of directors that the Compensation Discussion and Analysis be included in our proxy statement on Schedule 14A.

Thomas Everist, Chairman
Karen B. Fagg
Thomas C. Knudson
Patricia L. Moss

Summary Compensation Table for 2012

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Bonus ($) (d)	Stock Awards ($) (e)(1)	Option Awards ($) (f)	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)(2)	All Other Compensation ($) (i)	Total ($) (j)
Terry D. Hildestad	2012	750,000	–	897,277	–	518,250	355,027	38,224(3)	2,558,778
President and CEO	2011	750,000	–	1,084,318	–	954,750	739,760	37,499	3,566,327
	2010	750,000	–	830,137	–	762,750	480,532	37,499	2,860,918
Doran N. Schwartz	2012	300,000	–	179,445	–	103,650	100,935	34,224(3)	718,254
Vice President and CFO	2011	273,000	–	197,341	–	173,765	147,789	33,549	825,444
	2010	252,454	–	143,881	–	127,053	71,302	33,549	628,239
Steven L. Bietz	2012	360,500	–	258,765	–	347,973	329,969	37,884(3)	1,335,091
President and CEO	2011	360,500	–	312,704	–	229,198	545,066	37,159	1,484,627
of WBI Holdings, Inc.	2010	350,000	–	232,429	–	245,245	302,863	36,218	1,166,755
J. Kent Wells	2012	550,000	–	877,331	–	–	–	96,470(3)	1,523,801
President and CEO of	2011	367,671	916,685(4)	925,000(5)	–	1,007,306(6)	–	84,580(7)	3,301,242
Fidelity Exploration & Production Company	2010	–	–	–	–	–	–	–	–
William E. Schneider	2012	447,400	–	321,146	–	200,950	240,068	38,224(3)	1,247,788
Executive Vice President -	2011	447,400	–	388,086	–	436,215	412,085	37,499	1,721,285
Bakken Development	2010	447,400	–	297,122	–	37,805	306,909	37,499	1,126,735

(1) Amounts in this column represent the aggregate grant date fair value of the performance share awards calculated in accordance with Financial Accounting Standards Board generally accepted accounting principles for stock-based compensation in FASB Accounting Standards Codification Topic 718. This column was prepared assuming none of the awards will be forfeited. The amounts were calculated using a Monte Carlo simulation, as described in Note 13 of our audited financial statements in our Annual Report on Form 10-K for the year ended December 31, 2012.

(2) Amounts shown represent the change in the actuarial present value for years ended December 31, 2010, 2011, and 2012 for the named executive officers' accumulated benefits under the pension plan, excess SISP, and SISP, collectively referred to as the "accumulated pension change," plus above market earnings on deferred annual incentives, if any. The amounts shown are based on accumulated pension change and above market earnings as of December 31, 2010, 2011, and 2012, as follows:

	Accumulated Pension Change			Above Market Earnings		
Name	12/31/2010 ($)	12/31/2011 ($)	12/31/2012 ($)	12/31/2010 ($)	12/31/2011 ($)	12/31/2012 ($)
Terry D. Hildestad	462,186	728,587	331,845	18,346	11,173	23,182
Doran N. Schwartz	71,302	147,789	100,935	–	–	–
Steven L. Bietz	302,863	545,066	329,969	–	–	–
J. Kent Wells	–	–	–	–	–	–
William E. Schneider	277,507	393,768	201,944	29,402	18,317	38,124

(3)

	401(k) ($)(a)	Life Insurance Premium ($)	Matching Charitable Contribution ($)	Additional LTD Premium ($)	Relocation ($)	Parking ($)	Payment In Lieu of Medical Coverage ($)	Spousal Travel ($)	Total ($)
Terry D. Hildestad	36,250	174	1,800	–	–	–	–	–	38,224
Doran N. Schwartz	33,750	174	300	–	–	–	–	–	34,224
Steven L. Bietz	36,250	174	1,460	–	–	–	–	–	37,884
J. Kent Wells	20,000	174	–	435	69,695	3,600	1,200	1,366	96,470
William E. Schneider	36,250	174	1,800	–	–	–	–	–	38,224

(a) Represents company contributions to 401(k) plan, which include matching contributions and contributions made in lieu of pension plan accruals after pension plans were frozen at December 31, 2009.

(4) Includes a cash recruitment payment of $550,000 and guaranteed target annual incentive payment of $366,685.

(5) Represents the aggregate grant date fair value of the portion of Mr. Wells' additional 2011 annual incentive award that was paid in shares of our common stock calculated in accordance with Financial Accounting Standards Board generally accepted accounting principles for stock-based compensation in FASB Accounting Standards Codification Topic 718.

(6) Includes $82,296, the value of Mr. Wells' annual incentive earned above the guaranteed target amount and the $925,010 cash portion of Mr. Wells' additional 2011 annual incentive.

(7) The 2011 amount for Mr. Wells' all other compensation has been reduced to reflect the removal of $4,925, an excess 401(k) company match, that exceeded the limit when contributions from his prior company and current company were aggregated.

Grants of Plan-Based Awards in 2012

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards						
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All Other Stock Awards: Number of Shares of Stock or Units (#) (i)	All Other Option Awards: Number of Securities Underlying Options (#) (j)	Exercise or Base Price of Option Awards ($/Sh) (k)	Grant Date Fair Value of Stock and Option Awards ($) (l)
Terry D. Hildestad	3/1/2012(1)	187,500	750,000	1,500,000	–	–	–	–	–	–	–
	2/16/2012(2)	–	–	–	5,223	52,228	104,456	–	–	–	897,277
Doran N. Schwartz	3/1/2012(1)	37,500	150,000	300,000	–	–	–	–	–	–	–
	2/16/2012(2)	–	–	–	1,045	10,445	20,890	–	–	–	179,445
Steven L. Bietz	3/1/2012(1)	58,581	234,325	468,650	–	–	–	–	–	–	–
	2/16/2012(2)	–	–	–	1,506	15,062	30,124	–	–	–	258,765
J. Kent Wells	3/1/2012(1)	171,875	687,500	1,375,000	–	–	–	–	–	–	–
	2/16/2012(2)	–	–	–	5,107	51,067	102,134	–	–	–	877,331
William E. Schneider	3/1/2012(1)	72,703	290,810	581,620	–	–	–	–	–	–	–
	2/16/2012(2)	–	–	–	1,869	18,693	37,386	–	–	–	321,146

(1) Annual incentive for 2012 granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan, except for Mr. Schwartz whose award was granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan.

(2) Performance shares for the 2012-2014 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

Narrative Discussion Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Incentive Awards

Annual Incentive

On March 1, 2012, the compensation committee recommended the 2012 annual incentive award opportunities for our named executive officers and the board approved these opportunities at its meeting on March 1, 2012. These award opportunities are reflected in the Grants of Plan-Based Awards table at grant on March 1, 2012, in columns (c), (d), and (e) and in the Summary Compensation Table as earned with respect to 2012 in column (g).

Executive officers may receive a payment of annual cash incentive awards based upon achievement of annual performance measures with a threshold, target, and maximum level. A target incentive award is established based on a percent of the executive's base salary. Actual payment may range from 0% to 200% of the target based upon achievement of goals.

In order to be eligible to receive a payment of an annual incentive award under the Long-Term Performance-Based Incentive Plan, Messrs. Hildestad, Bietz, Wells, and Schneider must have remained employed by the company through December 31, 2012, unless the compensation committee determines otherwise. The committee has full discretion to determine the extent to which goals have been achieved, the payment level, whether any final payment will be made, and whether to adjust awards downward based upon individual performance. Unless otherwise determined and established in writing by the compensation committee within 90 days of the beginning of the performance period, the performance goals may not be adjusted if the adjustment would increase the annual incentive award payment. The compensation committee may use negative discretion and adjust any annual incentive award payment downward, using any subjective or objective measures as it shall determine, including but not limited to the 20% limitation described in the following sentence. The 20% limitation means that no more than 20% of after-tax earnings that are in excess of planned earnings at the business segment level for operating company executives and at the MDU Resources Group level for corporate executives will be paid in annual incentives to executives. The application of this limitation or any other reduction, and the methodology used in determining any such reduction, is in the sole discretion of the compensation committee.

With respect to annual incentive awards granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan, which includes Mr. Schwartz, participants who retire at age 65 during the year remain eligible to receive an award. Subject to the compensation committee's discretion, executives who terminate employment for other reasons are not eligible for an award. The compensation committee has full discretion to determine the extent to which goals have been achieved, the payment level, and whether any final payment will be made. Once performance goals are approved by the committee for executive incentive compensation plan awards, the committee generally does not modify the goals. However, if major unforeseen changes in economic and environmental conditions or other significant factors beyond the control of management substantially affected management's ability to achieve the specified performance goals, the committee, in consultation with the chief executive officer, may modify the performance goals. Such goal modifications will only be considered in years of unusually adverse or favorable external conditions.

Annual incentive award payments for Messrs. Hildestad, Schwartz, and Schneider were determined based on achievement of performance goals at the following business segments – (i) construction services and construction materials and contracting, (ii) exploration and production, (iii) pipeline and energy services, and (iv) electric and natural gas distribution - and were calculated as follows:

	Column A Percentage of Annual Incentive Target Achieved	Column B Percentage of Average Invested Capital	Column A x Column B
Construction Services Segment and Construction Materials and Contracting Segment	133.5%	29.2%	39.0%
Exploration and Production Segment	0.0%	28.1%	0.0%
Pipeline and Energy Services Segment	148.5%	8.8%	13.1%
Electric and Natural Gas Distribution Segments	50.0%	33.9%	17.0%
Total (Payout Percentage)			69.1%

The award opportunity available to Mr. Bietz was:

Pipeline and Energy Services' 2012 return on invested capital results as a % (weighted 37.5%) of 2012 target	Corresponding payment of annual incentive target based on return on invested capital
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

Pipeline and Energy Services' 2012 earnings per share results as a % (weighted 37.5%) of 2012 target	Corresponding payment of annual incentive target based on earnings per share
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

PROXY

MDU Resources Group, Inc.'s consolidated 2012 earnings per share results (weighted 25%)	Corresponding payment of annual incentive target based on consolidated earnings per share results
Less than 100%	0%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

The award opportunity available to Mr. Wells was:

Exploration and Production's 2012 return on invested capital results as a % (weighted 37.5%) of 2012 target	Corresponding payment of annual incentive target based on return on invested capital
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
108%	120%
116%	140%
124%	160%
132%	180%
140%	200%

Exploration and Production's 2012 earnings per share results as a % (weighted 37.5%) of 2012 target	Corresponding payment of annual incentive target based on earnings per share
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

MDU Resources Group, Inc.'s consolidated 2012 earnings per share results (weighted 25%)	Corresponding payment of annual incentive target based on consolidated earnings per share results
Less than 100%	0%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

For discussion of the specific incentive plan performance targets and results, please see the Compensation Discussion and Analysis.

Long-Term Incentive

On February 14, 2012, the compensation committee recommended long-term incentive grants to the named executive officers in the form of performance shares, and the board approved these grants at its meeting on February 16, 2012. These grants are reflected in columns (f), (g), (h), and (l) of the Grants of Plan-Based Awards table and in column (e) of the Summary Compensation Table.

If the company's 2012-2014 total shareholder return is positive, from 0% to 200% of the target grant will be paid out in February 2015, depending on our 2012-2014 total stockholder return compared to the total three-year stockholder returns of companies in our performance graph peer group. The payout percentage is determined as follows:

The Company's Percentile Rank	Payout Percentage of February 16, 2012 Grant
90th or higher	200%
70th	150%
50th	100%
40th	10%
Less than 40th	0%

Payouts for percentile ranks falling between the intervals will be interpolated. We also will pay dividend equivalents in cash on the number of shares actually earned for the performance period. The dividend equivalents will be paid in 2015 at the same time as the performance awards are paid.

If the common stock of a company in the peer group ceases to be traded at any time during the 2012-2014 performance period, the company will be deleted from the peer group. Percentile rank will be calculated without regard to the return of the deleted company. If MDU Resources Group, Inc. or a company in the peer group spins off a segment of its business, the shares of the spun-off entity will be treated as a cash dividend that is reinvested in MDU Resources Group, Inc. or the company in the peer group.

If the company's 2012-2014 total shareholder return is negative, the number of shares otherwise earned, if any, for the performance period will be reduced in accordance with the following table:

TSR	Reduction in Award
0% through -5%	50%
-5.01% through -10%	60%
-10.01% through -15%	70%
-15.01% through -20%	80%
-20.01% through -25%	90%
-25.01% or below	100%

Salary and Bonus in Proportion to Total Compensation

The following table shows the proportion of salary and bonus to total compensation:

Name	Salary ($)	Bonus ($)	Total Compensation ($)	Salary and Bonus as a % of Total Compensation
Terry D. Hildestad	750,000	–	2,558,778	29.3%
Doran N. Schwartz	300,000	–	718,254	41.8%
Steven L. Bietz	360,500	–	1,335,091	27.0%
J. Kent Wells	550,000	–	1,523,801	36.1%
William E. Schneider	447,400	–	1,247,788	35.9%

Outstanding Equity Awards at Fiscal Year-End 2012

	Option Awards					Stock Awards			
Name (a)	Number of Securities Underlying Unexercised Options Exercisable (#) (b)	Number of Securities Underlying Unexercised Options Unexercisable (#) (c)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#) (d)	Option Exercise Price ($) (e)	Option Expiration Date (f)	Number of Shares or Units of Stock That Have Not Vested (#) (g)	Market Value of Shares or Units of Stock That Have Not Vested ($) (h)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)(1)
Terry D. Hildestad	–	–	–	–	–	–	–	111,242(2)	2,362,780
Doran N. Schwartz	–	–	–	–	–	–	–	21,144(2)	449,099
Steven L. Bietz	–	–	–	–	–	–	–	32,041(2)	680,551
J. Kent Wells	–	–	–	–	–	–	–	51,067(2)	1,084,663
William E. Schneider	–	–	–	–	–	–	–	39,815(2)	845,671

(1) Value based on the number of performance shares reflected in column (i) multiplied by $21.24, the year-end closing price for 2012.

(2) Below is a breakdown by year of the plan awards:

Named Executive Officer	Award	Shares	End of Performance Period
Terry D. Hildestad	2010	4,771	12/31/12
	2011	54,243	12/31/13
	2012	52,228	12/31/14
Doran N. Schwartz	2010	827	12/31/12
	2011	9,872	12/31/13
	2012	10,445	12/31/14
Steven L. Bietz	2010	1,336	12/31/12
	2011	15,643	12/31/13
	2012	15,062	12/31/14
J. Kent Wells	2010	–	12/31/12
	2011	–	12/31/13
	2012	51,067	12/31/14
William E. Schneider	2010	1,708	12/31/12
	2011	19,414	12/31/13
	2012	18,693	12/31/14

Shares for the 2010 award are shown at the threshold level (10%) based on results for the 2010-2012 performance cycle below threshold.

Shares for the 2011 award are shown at the target level (100%) based on results for the first two years of the 2011-2013 performance cycle below target.

Shares for the 2012 award are shown at the target level (100%) based on results for the first year of the 2012-2014 performance cycle below target.

Option Exercises and Stock Vested During 2012

	Option Awards		Stock Awards	
Name (a)	Number of Shares Acquired on Exercise (#) (b)	Value Realized on Exercise ($) (c)	Number of Shares Acquired on Vesting (#) (d)(1)	Value Realized on Vesting ($) (e)(2)
Terry D. Hildestad	–	–	–	–
Doran N. Schwartz	–	–	–	–
Steven L. Bietz	–	–	–	–
J. Kent Wells	–	–	43,103	934,042
William E. Schneider	–	–	–	–

(1) Reflects the portion of Mr. Wells' additional 2011 annual incentive award that vested on February 16, 2012 and was paid in shares of our common stock determined by dividing $925,000 by the stock price on December 30, 2011, according to the terms of Mr. Wells' award.

(2) Reflects the value of the portion of Mr. Wells' additional 2011 annual incentive award that was paid in shares of our common stock based on our closing stock price of $21.67 on February 16, 2012.

Pension Benefits for 2012

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
Terry D. Hildestad	MDU Pension Plan	35	1,662,318	–
	SISP I(1)(3)	10	2,126,747	–
	SISP II(2)(3)	10	3,511,576	–
	SISP Excess(4)	35	378,943	–
Doran N. Schwartz	MDU Pension Plan	4	94,002	–
	SISP II(2)(3)	5	489,028	–
Steven L. Bietz	WBI Pension Plan	28	1,154,443	–
	SISP I(1)(3)	10	799,197	–
	SISP II(2)(3)	10	768,065	–
	SISP Excess(4)	28	103,162	–
J. Kent Wells(5)	–	–	–	–
William E. Schneider	KR Pension Plan	16	800,720	–
	SISP I(1)(3)	10	1,479,910	–
	SISP II(2)(3)	10	1,748,343	–

(1) Grandfathered under Section 409A.

(2) Not grandfathered under Section 409A.

(3) Years of credited service only affects vesting under SISP I and SISP II. The number of years of credited service in the table reflects the years of vesting service completed in SISP I and SISP II as of December 31, 2012, rather than total years of service with the company. Ten years of vesting service is required to obtain the full benefit under these plans. The present value of accumulated benefits was calculated by assuming the named executive officer would have ten years of vesting service on the assumed benefit commencement date; therefore, no reduction was made to reflect actual vesting levels.

(4) The number of years of credited service under the SISP excess reflects the years of credited benefit service in the appropriate pension plan as of December 31, 2009, when the pension plans were frozen, rather than the years of participation in the SISP excess. We reflect years of credited benefit service in the appropriate pension plan because the SISP excess provides a benefit that is based on benefits that would have been payable under the pension plans absent Internal Revenue Code limitations.

(5) Mr. Wells is not eligible to participate in our pension plan and does not participate in the SISP.

The amounts shown for the pension plan and SISP excess represent the actuarial present values of the executives' accumulated benefits accrued as of December 31, 2012, calculated using a 3.45%, 3.59%, 3.76%, and 3.58% discount rate for the SISP excess, MDU pension plan, WBI pension plan, and KR pension plan, respectively, the 2013 IRS Static Mortality Table for post-retirement mortality, and no recognition of future salary increases or pre-retirement mortality. The assumed retirement ages for these benefits was age 60 for Messrs. Schwartz and Bietz. This is the earliest age at which the executives could begin receiving unreduced benefits. Retirement on December 31, 2012, was assumed for Messrs. Hildestad and Schneider, who were age 63 and 64, respectively, on that date. The amounts shown for the SISP I and SISP II were determined using a 3.45% discount rate and assume benefits commenced at age 65.

Pension Plans

Messrs. Hildestad and Schwartz participate in the MDU Resources Group, Inc. Pension Plan for Non-Bargaining Unit Employees, which we refer to as the MDU pension plan. Mr. Bietz participates in the Williston Basin Interstate Pipeline Company Pension Plan, which we refer to as the WBI pension plan. Mr. Schneider participates in the Knife River Corporation Salaried Employees' Pension Plan, which we refer to as the KR pension plan. Pension benefits under the pension plans are based on the participant's average annual salary over the 60 consecutive month period in which the participant received the highest annual salary during the participant's final 10 years of service. For this purpose, only a participant's salary is considered; incentives and other forms of compensation are not included. Benefits are determined by multiplying (1) the participant's years of credited service by (2) the sum of (a) the average annual salary up to the social security integration level times 1.1% and (b) the average annual salary over the social security integration level times 1.45%. The KR pension plan uses the same formula except that 1.2% and 1.6% are used instead of 1.1% and 1.45%. The maximum years of service recognized when determining benefits under the pension plans is 35. Pension plan benefits are not reduced for social security benefits.

Each of the pension plans was amended to cease benefit accruals as of December 31, 2009, meaning the normal retirement benefit will not change. The years of credited service in the table reflect the named executive officers' years of credited service as of December 31, 2009.

To receive unreduced retirement benefits under the MDU pension plan and the WBI pension plan, participants must either remain employed until age 60 or elect to defer commencement of benefits until age 60. Under the KR pension plan, participants must remain employed until age 62 or elect to defer commencement of benefits until age 62 to receive unreduced benefits. Mr. Hildestad was eligible for unreduced retirement benefits under the MDU pension plan, and Mr. Schneider was eligible for unreduced retirement benefits under the KR pension plan on December 31, 2012. Participants whose employment terminates between the ages of 55 and 60, with 5 years of service under the MDU pension plan and the WBI pension plan are eligible for early retirement benefits. Early retirement benefits are determined by reducing the normal retirement benefit by 0.25% per month for each month before age 60 in the MDU pension plan and the WBI pension plan. If a participant's employment terminates before age 55, the same reduction applies for each month the termination occurs before age 62, with the reduction capped at 21%.

Benefits for single participants under the pension plans are paid as straight life annuities and benefits for married participants are paid as actuarially reduced annuities with a survivor benefit for spouses, unless participants choose otherwise. Participants hired before January 1, 2004, who terminate employment before age 55 may elect to receive their benefits in a lump sum. Mr. Bietz would have been eligible for a lump sum if he had retired on December 31, 2012.

The Internal Revenue Code limits the amounts that may be paid under the pension plans and the amount of compensation that may be recognized when determining benefits. In 2009 when the pension plans were frozen, the maximum annual benefit payable under the pension plans was $195,000 and the maximum amount of compensation that could be recognized when determining benefits was $245,000.

Supplemental Income Security Plan

We also offer key managers and executives, including our named executive officers, except Mr. Wells, benefits under our nonqualified retirement plan, which we refer to as the Supplemental Income Security Plan or SISP. Benefits under the SISP consist of:

- a supplemental retirement benefit intended to augment the retirement income provided under the pension plans – we refer to this benefit as the regular SISP benefit
- an excess retirement benefit relating to Internal Revenue Code limitations on retirement benefits provided under the pension plans – we refer to this benefit as the SISP excess benefit, and
- death benefits – we refer to these benefits as the SISP death benefit.

SISP benefits are forfeited if the participant's employment is terminated for cause.

Regular SISP Benefits and Death Benefits

Regular SISP benefits and death benefits are determined by reference to one of two schedules attached to the SISP – the original schedule or the amended schedule. Our compensation committee, after receiving recommendations from our chief executive officer, determines the level at which participants are placed in the schedules. A participant's placement is generally, but not always, determined by reference to the participant's annual base salary. Benefit levels in the amended schedule, which became effective on January 1, 2010, are 20% lower than the benefit levels in the original schedule. The amended schedule applies to new participants and participants who receive a benefit level increase on or after January 1, 2010. None of the named executive officers have received a benefit level increase since the amended schedule became effective.

Participants can elect to receive (1) the regular SISP benefit only, (2) the SISP death benefit only, or (3) a combination of both. Regardless of the participant's election, if the participant dies before the regular SISP benefit would commence, only the SISP death benefit is provided. If the participant elects to receive both a regular SISP benefit and a SISP death benefit, each of the benefits is reduced proportionately.

The regular SISP benefits reflected in the table above are based on the assumption that the participant elects to receive only the regular SISP benefit. The present values of the SISP death benefits that would be provided if the named executive officers had died on December 31, 2012, prior to the commencement of regular SISP benefits, are reflected in the table that appears in the section entitled "Potential Payments upon Termination or Change of Control."

Regular SISP benefits that were vested as of December 31, 2004, and were grandfathered under Section 409A of the Internal Revenue Code remain subject to SISP provisions then in effect, which we refer to as SISP I benefits. Regular SISP benefits that are subject to Section 409A of the Internal Revenue Code, which we refer to as SISP II benefits, are governed by amended provisions intended to comply with Section 409A. Participants generally have more discretion with respect to the distributions of their SISP I benefits.

The time and manner in which the regular SISP benefits are paid depend on a variety of factors, including the time and form of benefit elected by the participant and whether the benefits are SISP I or SISP II benefits. Unless the participant elects otherwise, the SISP I benefits are paid over 180 months, with benefits commencing when the participant attains age 65 or, if later, when the participant retires. The SISP II benefits commence when the participant attains age 65 or, if later, when the participant retires, subject to a six-month delay if the participant is subject to the provisions of Section 409A of the Internal Revenue Code that require delayed commencement of these types of retirement benefits. The SISP II benefits are paid over 180 months or, if commencement of payments is delayed for six months, 173 months. If the commencement of benefits is delayed for six months, the first payment includes the payments that would have been paid during the six-month period plus interest equal to one-half of the annual prime interest rate on the participant's last date of employment. If the participant dies after the regular SISP benefits have begun but before receipt of all of the regular SISP benefits, the remaining payments are made to the participant's designated beneficiary.

Rather than receiving their regular SISP I benefits in equal monthly installments over 15 years commencing at age 65, participants can elect a different form and time of commencement of their SISP I benefits. Participants can elect to defer commencement of the regular SISP I benefits. If this is elected, the participant retains the right to receive a monthly SISP death benefit if death occurs prior to the commencement of the regular SISP I benefit.

Participants also can elect to receive their SISP I benefits in one of three actuarially equivalent forms – a life annuity, 100% joint and survivor annuity, or a joint and two-thirds joint and survivor annuity, provided that the cost of providing these actuarial equivalent forms of benefits does not exceed the cost of providing the normal form of benefit. Neither the election to receive an actuarially equivalent benefit nor the administrator's right to pay the regular SISP benefit in the form of an actuarially equivalent lump sum are available with respect to SISP II benefits.

To promote retention, the regular SISP benefits are subject to the following 10-year vesting schedule:

- 0% vesting for less than 3 years of participation
- 20% vesting for 3 years of participation
- 40% vesting for 4 years of participation and
- an additional 10% vesting for each additional year of participation up to 100% vesting for 10 years of participation.

There is an additional vesting requirement on benefit level increases for the regular SISP benefit granted on or after January 1, 2010. The requirement applies only to the increased benefit level. The increased benefit vests after the later of three additional years of participation in the SISP or the end of the regular vesting schedule described above. The additional three-year vesting requirement for benefit level increases is pro-rated for participants who are officers, attain age 65, and, pursuant to the company's bylaws, are required to retire prior to the end of the additional vesting period as follows:

- 33% of the increase vests for participants required to retire at least one year but less than two years after the increase is granted and
- 66% of the increase vests for participants required to retire at least two years but less than three years after the increase is granted.

The benefit level increases of participants who attain age 65 and are required to retire pursuant to the company's bylaws will be further reduced to the extent the participants are not fully vested in their regular SISP benefit under the 10-year vesting schedule described above. The additional vesting period associated with a benefit level increase may be waived by the compensation committee.

SISP death benefits become fully vested if the participant dies while actively employed. Otherwise, the SISP death benefits are subject to the same vesting schedules as the regular SISP benefits.

The SISP also provides that if a participant becomes totally disabled, the participant will continue to receive credit for up to two additional years under the SISP as long as the participant is totally disabled during such time. Since the named executive officers other than Mr. Schwartz are fully vested in their SISP benefits, this would not result in any incremental benefit for the named executive officers other than Mr. Schwartz. The present value of these two additional years of service for Mr. Schwartz is reflected in the table in "Potential Payments upon Termination or Change of Control" below.

SISP Excess Benefits

SISP excess benefits are equal to the difference between (1) the monthly retirement benefits that would have been payable to the participant under the pension plans absent the limitations under the Internal Revenue Code and (2) the actual benefits payable to the participant under the pension plans. Participants are only eligible for the SISP excess benefits if (1) the participant is fully vested under the pension plan, (2) the participant's employment terminates prior to age 65, and (3) benefits under the pension plan are reduced due to limitations under the Internal Revenue Code on plan compensation. Effective January 1, 2005, participants who were not then vested in the SISP excess benefits were also required to remain actively employed by the company until age 60. In 2009, the plan was amended to limit eligibility for the SISP excess benefit to current SISP participants (1) who were already vested in the SISP excess benefit or (2) who would become vested in the SISP excess benefits if they remain employed with the company until age 60. The plan was further amended to freeze the SISP excess benefits to a maximum of the benefit level payable based on the participant's years of service and compensation level as of December 31, 2009. Messrs. Hildestad, Bietz, and Schneider would be entitled to the SISP excess benefit if they were to terminate employment prior to age 65. Messrs. Schwartz and Wells are not eligible for this benefit.

Benefits generally commence six months after the participant's employment terminates and continue to age 65 or until the death of the participant, if prior to age 65. If a participant who dies prior to age 65 elected a joint and survivor benefit, the survivor's SISP excess benefit is paid until the date the participant would have attained age 65.

Nonqualified Deferred Compensation for 2012

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Earnings in Aggregate Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
Terry D. Hildestad	–	–	53,105	–	1,001,633
Doran N. Schwartz	–	–	–	–	–
Steven L. Bietz	–	–	–	–	–
J. Kent Wells	–	–	–	–	–
William E. Schneider	–	–	87,334	–	1,647,225(1)

(1) Includes $392,000 which was reported in the Summary Compensation Table for 2006 in column (g) and $37,805 which is reported for 2010 in column (g) of the Summary Compensation Table in this proxy statement.

Participants in the executive incentive compensation plans may elect to defer up to 100% of their annual incentive awards. Deferred amounts accrue interest at a rate determined annually by the compensation committee. The interest rate in effect for 2012 was 5.46% or the "Moody's Rate," which is the average of (i) the number that results from adding the daily Moody's U.S. Long-Term Corporate Bond Yield Average for "A" rated companies as of the last day of each month for the 12-month period ending October 31 and dividing by 12 and (ii) the number that results from adding the daily Moody's U.S. Long-Term Corporate Bond Yield Average for "BBB" rated companies as of the last day of each month for the 12-month period ending October 31 and dividing by 12. The deferred amount will be paid in accordance with the participant's election, following termination of employment or beginning in the fifth year following the year the award was granted. The amounts will be paid in accordance with the participant's election in a lump sum or in monthly installments not to exceed 120 months. In the event of a change of control, all amounts become immediately payable.

A change of control is defined as:

- an acquisition during a 12-month period of 30% or more of the total voting power of our stock
- an acquisition of our stock that, together with stock already held by the acquirer, constitutes more than 50% of the total fair market value or total voting power of our stock
- replacement of a majority of the members of our board of directors during any 12-month period by directors whose appointment or election is not endorsed by a majority of the members of our board of directors or
- acquisition of our assets having a gross fair market value at least equal to 40% of the total gross fair market value of all of our assets.

Potential Payments upon Termination or Change of Control

The following tables show the payments and benefits our named executive officers would receive in connection with a variety of employment termination scenarios and upon a change of control. For the named executive officers, the information assumes the terminations and the change of control occurred on December 31, 2012. All of the payments and benefits described below would be provided by the company or its subsidiaries.

The tables exclude compensation and benefits provided under plans or arrangements that do not discriminate in favor of the named executive officers and that are generally available to all salaried employees, such as benefits under our qualified defined benefit pension plan (for employees hired before 2006), accrued vacation pay, continuation of health care benefits, and life insurance benefits. The tables also do not include the named executive officers' benefits under our nonqualified deferred compensation plans, which are reported in the Nonqualified Deferred Compensation for 2012 table. See the Pension Benefits for 2012 table and the Nonqualified Deferred Compensation for 2012 table, and accompanying narratives, for a description of the named executive officers' accumulated benefits under our qualified defined benefit pension plans and our nonqualified deferred compensation plans.

The calculation of the present value of excess SISP benefits our named executive officers would be entitled to upon termination of employment under the SISP was computed based on calculations assuming an age rounded to the nearest whole year of age. Actual payments may differ. The terms of the excess SISP benefit are described following the Pension Benefits for 2012 table.

We provide disability benefits to some of our salaried employees equal to 60% of their base salary, subject to a cap on the amount of base salary taken into account when calculating benefits. For officers, the limit on base salary is $200,000. For other salaried employees, the limit is $100,000. For all salaried employees, disability payments continue until age 65 if disability occurs at or before age 60 and for 5 years if disability occurs between the ages of 60 and 65. Disability benefits are reduced for amounts paid as retirement benefits. The amounts in the tables reflect the present value of the disability benefits attributable to the additional $100,000 of base salary recognized for executives under our disability program, subject to the 60% limitation, after reduction for amounts that would be paid as retirement benefits. As the tables reflect, the reduction for amounts paid as retirement benefits would eliminate disability benefits assuming a termination of employment on December 31, 2012 for Messrs. Hildestad, Bietz, and Schneider.

Upon a change of control, share-based awards granted under our Long-Term Performance-Based Incentive Plan vest and non-share-based awards are paid in cash. All performance share awards for Messrs. Hildestad, Schwartz, Bietz, Wells, and Schneider and the annual incentives for Messrs. Hildestad, Bietz, Wells, and Schneider, which were awarded under the Long-Term Performance-Based Incentive Plan, would vest at their target levels. For this purpose, the term "change of control" is defined as:

- the acquisition by an individual, entity, or group of 20% or more of our outstanding common stock
- a change in a majority of our board of directors since April 22, 1997, without the approval of a majority of the board members as of April 22, 1997, or whose election was approved by such board members
- consummation of a merger or similar transaction or sale of all or substantially all of our assets, unless our stockholders immediately prior to the transaction beneficially own more than 60% of the outstanding common stock and voting power of the resulting corporation in substantially the same proportions as before the merger, no person owns 20% or more of the resulting corporation's outstanding common stock or voting power except for any such ownership that existed before the merger and at least a majority of the board of the resulting corporation is comprised of our directors or
- stockholder approval of our liquidation or dissolution.

Performance share awards will be forfeited if the participant's employment terminates for any reason before the participant has reached age 55 and completed 10 years of service. Performance shares and related dividend equivalents for those participants whose employment is terminated other than for cause after the participant has reached age 55 and completed 10 years of service will be prorated as follows:

- if the termination of employment occurs during the first year of the performance period, the shares are forfeited
- if the termination of employment occurs during the second year of the performance period, the executive receives a prorated portion of any performance shares earned based on the number of months employed during the performance period and
- if the termination of employment occurs during the third year of the performance period, the executive receives the full amount of any performance shares earned.

As of December 31, 2012, Messrs. Schwartz, Bietz, and Wells had not satisfied this requirement. Accordingly, if a December 31, 2012 termination other than for cause without a change of control is assumed, the named executive officers' 2012-2014 performance share awards would be forfeited, any amounts earned under the 2011-2013 performance share awards for Messrs. Hildestad and Schneider would be reduced by one-third and such award for Messrs. Schwartz and Bietz would be forfeited, and any amounts earned under the 2010-2012 performance share awards for Messrs. Hildestad and Schneider would not be reduced and the award for Messrs. Schwartz and Bietz would be forfeited. Mr. Wells had no 2011-2013 or 2010-2012 performance share awards. The number of performance shares earned following a termination depends on actual performance through the full performance period. As actual performance for the 2010-2012 performance share awards has been determined, the amounts for these awards in the event of a termination without a change of control were based on actual performance, which resulted in vesting of 0% of the target award. For the 2011-2013 performance share awards, because we do not know what actual performance through the entire performance period will be, we have assumed target performance will be achieved and, therefore, show two-thirds of the target award. No amounts are shown for the 2012-2014 performance share awards because such awards would be forfeited. Although vesting would only occur after completion of the performance period, the amounts shown in the tables were not reduced to reflect the present value of the performance shares that could vest. Dividend equivalents attributable to earned performance shares would also be paid. Dividend equivalents accrued through December 31, 2012, are included in the amounts shown.

The value of the vesting of performance shares shown in the tables was determined by multiplying the number of performance shares that would vest due to termination or a change of control by the closing price of our stock on December 31, 2012.

The compensation committee may consider providing severance benefits on a case-by-case basis for employment terminations. The compensation committee adopted a checklist of factors in February 2005 to consider when determining whether any such severance benefits should be paid. The tables do not reflect any such severance benefits, as these benefits are made in the discretion of the committee on a case-by-case basis and it is not possible to estimate the severance benefits, if any, that would be paid.

Terry D. Hildestad

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
Compensation:							
Short-term Incentive(1)						750,000	750,000
2010-2012 Performance Shares						1,107,087	1,107,087
2011-2013 Performance Shares	816,176	816,176		816,176	816,176	1,224,265	1,224,265
2012-2014 Performance Shares						1,144,577	1,144,577
Benefits and Perquisites:							
Regular SISP(2)	5,709,419	5,709,419			5,709,419	5,709,419	
Excess SISP(3)	378,944	378,944			378,944	378,944	
SISP Death Benefits(4)				12,024,426			
Total	**6,904,539**	**6,904,539**		**12,840,602**	**6,904,539**	**10,314,292**	**4,225,929**

(1) Represents the target 2012 annual incentive, which would be deemed earned upon change of control under the Long-Term Performance-Based Incentive Plan.

(2) Represents the present value of Mr. Hildestad's vested regular SISP benefit as of December 31, 2012, which was $42,710 per month for 15 years, commencing at age 65. Present value was determined using a 3.45% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2012 table.

(3) Represents the present value of all excess SISP benefits Mr. Hildestad would be entitled to upon termination of employment under the SISP. Present value was determined using a 3.45% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2012 table.

(4) Represents the present value of 180 monthly payments of $85,420 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 3.45% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2012 table.

Doran N. Schwartz

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
Compensation:							
2010-2012 Performance Shares						191,882	191,882
2011-2013 Performance Shares						222,811	222,811
2012-2014 Performance Shares						228,902	228,902
Benefits and Perquisites:							
Regular SISP	244,273(1)	244,273(1)			341,982(2)	244,273(1)	
SISP Death Benefits(3)				2,055,217			
Disability Benefits(4)					855,522		
Total	**244,273**	**244,273**		**2,055,217**	**1,197,504**	**887,868**	**643,595**

(1) Represents the present value of Mr. Schwartz's vested regular SISP benefit as of December 31, 2012, which was $3,650 per month for 15 years, commencing at age 65. Present value was determined using a 3.45% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2012 table.

(2) Represents the present value of Mr. Schwartz's vested SISP benefit described in footnote 1, adjusted to reflect the increase in the present value of his regular SISP benefit that would result from an additional two years of vesting under the SISP. Present value was determined using a 3.45% discount rate.

(3) Represents the present value of 180 monthly payments of $14,600 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 3.45% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2012 table.

(4) Represents the present value of the disability benefit after reduction for amounts that would be paid as retirement benefits. Present value was determined using a 3.59% discount rate.

Steven L. Bietz

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
Compensation:							
Short-term Incentive(1)						234,325	234,325
2010-2012 Performance Shares						309,972	309,972
2011-2013 Performance Shares						353,063	353,063
2012-2014 Performance Shares						330,084	330,084
Benefits and Perquisites:							
Regular SISP(2)	1,556,929	1,556,929			1,556,929	1,556,929	
Excess SISP(3)	180,597	180,597			180,597	180,597	
SISP Death Benefits(4)				4,535,554			
Total	**1,737,526**	**1,737,526**		**4,535,554**	**1,737,526**	**2,964,970**	**1,227,444**

(1) Represents the target 2012 annual incentive, which would be deemed earned upon change of control under the Long-Term Performance-Based Incentive Plan.

(2) Represents the present value of Mr. Bietz's vested regular SISP benefit as of December 31, 2012, which was $16,110 per month for 15 years, commencing at age 65. Present value was determined using a 3.45% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2012 table.

(3) Represents the present value of all excess SISP benefits Mr. Bietz would be entitled to upon termination of employment under the SISP. Present value was determined using a 3.45% discount rate. The terms of the excess SISP benefit are described following the Pension Benefits for 2012 table.

(4) Represents the present value of 180 monthly payments of $32,220 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 3.45% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2012 table.

J. Kent Wells

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
Compensation:							
Short-term Incentive(1)						687,500	687,500
2012-2014 Performance Shares						1,119,133	1,119,133
Benefits and Perquisites:							
Disability Benefits (2)					452,506		
Total					**452,506**	**1,806,633**	**1,806,633**

(1) Represents the target 2012 annual incentive, which would be deemed earned upon change of control under the Long-Term Performance-Based Incentive Plan.

(2) Represents the present value of the disability benefit. Present value was determined using a 3.76% discount rate.

PROXY

William E. Schneider

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
Compensation:							
Short-term Incentive(1)						290,810	290,810
2010-2012 Performance Shares						396,249	396,249
2011-2013 Performance Shares	292,124	292,124		292,124	292,124	438,174	438,174
2012-2014 Performance Shares						409,657	409,657
Benefits and Perquisites:							
Regular SISP(2)	3,161,624	3,161,624			3,161,624	3,161,624	
SISP Death Benefits(3)				6,433,110			
Total	**3,453,748**	**3,453,748**		**6,725,234**	**3,453,748**	**4,696,514**	**1,534,890**

(1) Represents the target 2012 annual incentive, which would be deemed earned upon change of control under the Long-Term Performance-Based Incentive Plan.

(2) Represents the present value of Mr. Schneider's vested regular SISP benefit as of December 31, 2012, which was $22,850 per month for 15 years, commencing at age 65. Present value was determined using a 3.45% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2012 table.

(3) Represents the present value of 180 monthly payments of $45,700 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 3.45% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2012 table.

Director Compensation for 2012

Name (a)	Fees Earned or Paid in Cash ($) (b)	Stock Awards ($) (c)(1)	Option Awards ($) (d)	Non-Equity Incentive Plan Compensation ($) (e)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (f)	All Other Compensation ($) (g)(2)	Total ($) (h)
Thomas Everist	65,000	110,000	–	–	–	174	175,174
Karen B. Fagg	65,000	110,000	–	–	–	174	175,174
A. Bart Holaday	55,000(3)	110,000	–	–	–	174	165,174
Dennis W. Johnson	70,000	110,000	–	–	–	174	180,174
Thomas C. Knudson	55,000	110,000	–	–	–	674	165,674
Richard H. Lewis	55,000	110,000	–	–	–	174	165,174
Patricia L. Moss	55,000(4)	110,000	–	–	–	174	165,174
Harry J. Pearce	130,000	110,000	–	–	–	174	240,174
John K. Wilson	55,000(5)	110,000	–	–	–	174	165,174

(1) This column reflects the aggregate grant date fair value of 5,467 shares of MDU Resources Group, Inc. stock purchased for our non-employee directors measured in accordance with Financial Accounting Standards Board generally accepted accounting principles for stock based compensation in FASB Accounting Standards Codification Topic 718. The grant date fair value is based on the purchase price of our common stock on the grant date on November 19, 2012, which was $20.118. The $14.89 in cash paid to each director for the fractional shares is included in the amounts reported in column (c) to this table.

(2) Group life insurance premium of $174 and a matching charitable contribution of $500 for Mr. Knudson.

(3) Includes $14,999 that Mr. Holaday received in our common stock in lieu of cash.

(4) Includes $27,481 that Ms. Moss received in our common stock in lieu of cash.

(5) Includes $54,982 that Mr. Wilson received in our common stock in lieu of cash.

The following table shows the cash and stock retainers payable to our non-employee directors.

Base Retainer	$55,000
Additional Retainers:	
Non-Executive Chairman	75,000
Lead Director, if any	33,000
Audit Committee Chairman	15,000
Compensation Committee Chairman	10,000
Nominating and Governance Committee Chairman	10,000
Annual Stock Grant(1)	110,000

(1) The annual stock grant is a grant of shares equal in value to $110,000.

There are no meeting fees.

In addition to liability insurance, we maintain group life insurance in the amount of $100,000 on each non-employee director for the benefit of each director's beneficiaries during the time each director serves on the board. The annual cost per director is $174.

Directors may defer all or any portion of the annual cash retainer and any other cash compensation paid for service as a director pursuant to the Deferred Compensation Plan for Directors. Deferred amounts are held as phantom stock with dividend accruals and are paid out in cash over a five-year period after the director leaves the board.

Directors are reimbursed for all reasonable travel expenses including spousal expenses in connection with attendance at meetings of the board and its committees. All amounts together with any other perquisites were below the disclosure threshold for 2012.

Our post-retirement income plan for directors was terminated in May 2001 for current and future directors. The net present value of each director's benefit was calculated and converted into phantom stock. Payment is deferred pursuant to the Deferred Compensation Plan for Directors and will be made in cash over a five-year period after the director's retirement from the board.

Our director stock ownership policy contained in our corporate governance guidelines requires each director to own our common stock equal in value to five times the director's annual cash base retainer. Shares acquired through purchases on the open market and participation in our director stock plans will be considered in ownership calculations as will ownership of our common stock by a spouse. A director is allowed five years commencing January 1 of the year following the year of that director's initial election to the board to meet the requirements. The level of common stock ownership is monitored with an annual report made to the compensation committee of the board. For stock ownership, please see "Security Ownership."

Narrative Disclosure of our Compensation Policies and Practices as They Relate to Risk Management

The human resources department has conducted an assessment of the risks arising from our compensation policies and practices for all employees and concluded that none of these risks is reasonably likely to have a material adverse effect on the company. Based on the human resources department's assessment and taking into account information received from the risk identification process, senior management and our management policy committee concluded that risks arising from our compensation policies and practices for all employees are not reasonably likely to have a material adverse effect on the company. After review and discussion with senior management, the compensation committee concurred with this assessment.

As part of its assessment of the risks arising from our compensation policies and practices for all employees, the human resources department identified the principal areas of risk faced by the company that may be affected by our compensation policies and practices for all employees, including any risks resulting from our operating businesses' compensation policies and practices. In assessing the risks arising from our compensation policies and practices, the human resources department identified the following practices designed to prevent excessive risk taking:

Business management and governance practices

- risk management is a specific performance competency to annual performance assessment of Section 16 officers
- board oversight on capital expenditure and operating plans that promotes careful consideration of financial assumptions
- limitation on business acquisitions without board approval
- employee integrity training programs and anonymous reporting systems
- quarterly risk assessment reports at audit committee meetings and
- prohibitions on holding company stock in an account that is subject to a margin call, pledging company stock as collateral for a loan, and hedging of company stock by Section 16 officers and directors.

Compensation practices

- active compensation committee review of executive compensation, including comparison of executive compensation to total stockholder return ratio to the ratio for the performance graph peer group (PEER Analysis)
- the initial determination of a position's salary grade to be at or near the 50th percentile of base salaries paid to similar positions at peer group companies and/or relevant industry companies
- consideration of peer group and/or relevant industry practices to establish appropriate compensation target amounts
- a balanced compensation mix of fixed salary and annual or long-term incentives tied to the company's financial performance
- use of interpolation for annual and long-term incentive awards to avoid payout cliffs
- negative discretion to adjust any annual or long-term incentive award payment downward
- use of caps on annual incentive awards and long-term incentive stock grant awards (200% of target for awards granted in 2012)
- discretionary clawbacks on incentive payments in the event of a financial restatement
- use of performance shares, rather than stock options or stock appreciation rights, as equity component of incentive compensation
- use of performance shares with a relative, rather than an absolute, total stockholder return performance goal and mandatory reduction in award if total stockholder return is negative
- use of three-year performance periods to discourage short-term risk-taking

- substantive incentive goals measured primarily by return on invested capital and earnings per share criteria, which encourage balanced performance and are important to stockholders
- use of financial performance metrics that are readily monitored and reviewed
- regular review of the appropriateness of the companies in the performance graph peer group
- stock ownership requirements for executives participating in the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan and the board
- mandatory holding periods for 50% of any net after-tax shares earned under long-term incentive awards granted in 2011 and thereafter and
- use of independent consultants in establishing pay targets at least biennially.

INFORMATION CONCERNING EXECUTIVE OFFICERS

At the first annual meeting of the board after the annual meeting of stockholders, our board of directors elects our executive officers, who serve until their successors are chosen and qualify. A majority of our board of directors may remove any executive officer at any time. Information concerning our executive officers, including their ages, present corporate positions, and business experience, is as follows:

Name	Age	Present Corporate Position and Business Experience
David L. Goodin	51	Mr. Goodin was elected President and Chief Executive Officer of the company and a director effective January 4, 2013. For more information about Mr. Goodin, see "Election of Directors."
Steven L. Bietz	54	Mr. Bietz was elected president and chief executive officer of WBI Holdings, Inc. effective March 4, 2006; president effective January 2, 2006; executive vice president and chief operating officer effective September 1, 2002; vice president-administration and chief accounting officer effective November 3, 1999; vice president-administration effective February 1997; and controller effective January 1994.
William R. Connors	51	Mr. Connors was elected vice president–renewable resources of MDU Resources Group, Inc., effective September 1, 2008. Prior to that, he was vice president-business development of Cascade Natural Gas Corporation effective November 2007; vice president-origination, contracts & regulatory of Centennial Energy Resources, LLC, effective January 2007; vice president-origination, contracts & regulatory of Centennial Power, Inc., effective July 2005; and, was first employed as vice president-contracts & regulatory of Centennial Power, Inc., effective July 2004. Prior to that Mr. Connors was of counsel to Miller Nash, LLP, a law firm in Seattle, Washington.
Mark A. Del Vecchio	53	Mr. Del Vecchio was elected vice president–human resources on October 1, 2007. From November 3, 2003 to October 1, 2007, Mr. Del Vecchio was director of executive programs and compensation. From April 1996 to October 31, 2003, Mr. Del Vecchio was vice president and member of The Carter Group, LLC, an executive search and management consulting company.
John G. Harp	60	Mr. Harp was elected chief executive officer of Knife River Corporation effective January 1, 2012, and continues to serve as chief executive officer of MDU Construction Services Group, Inc. He was elected president and chief executive officer of Utility Services Inc., which is now MDU Construction Services Group, Inc., effective September 29, 2004. From May 2004 to September 29, 2004, Mr. Harp was vice president of Ledcor Technical Services Inc., a provider of fiber optic cable maintenance services. From April 2001 to May 2004, he was president of JODE CORP., a broadband maintenance company. Mr. Harp sold JODE CORP. to Ledcor Construction in May 2004. Prior to that, he was president of Harp Line Constructors Co. and Harp Engineering, Inc. from July 1998, when they were bought by Utility Services Inc., to April 2001.
Nicole A. Kivisto	39	Ms. Kivisto was elected vice president, controller and chief accounting officer effective February 17, 2010. Prior to that she was controller effective December 1, 2005; a financial analyst IV in the Corporate Planning Department effective May 2003; a financial and investor relations analyst in the Investor Relations Department effective May 2000; and a financial analyst in the Corporate Accounting Department effective July 1995.
Douglass A. Mahowald	63	Mr. Mahowald was elected treasurer and assistant secretary effective February 17, 2010. Prior to that he was the assistant treasurer and assistant secretary effective August 1992; treasury services manager effective November 1982; and budget statistician effective February 1982.
K. Frank Morehouse	54	Mr. Morehouse was elected president and chief executive officer of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company effective January 4, 2013. Prior to that, he was executive vice president and general manager of Cascade Natural Gas Corporation effective April 1, 2009, and Intermountain Gas Company effective October 1, 2008; vice president-operations of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. effective January 29, 2007; Region Manager for Montana-Dakota Utilities Co. effective October 1, 2004; and Region Manager of Great Plains Natural Gas Co. when it was acquired July 1, 2000.
Cynthia J. Norland	58	Ms. Norland was elected vice president–administration effective July 16, 2007. Prior to that she was the assistant vice president–administration effective January 17, 2007; associate general counsel in the Legal Department effective March 6, 2004; and senior attorney in the Legal Department effective June 1, 1995.
Paul K. Sandness	58	Mr. Sandness was elected general counsel and secretary of the company, its divisions and major subsidiaries effective April 6, 2004. He also was elected a director of the company's principal subsidiaries and was appointed to the Managing Committees of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. Prior to that he served as a senior attorney effective 1987 and as an assistant secretary of several subsidiary companies.

William E. Schneider	64	Mr. Schneider was elected executive vice president–Bakken Development effective January 1, 2012. Prior to that, he was president and chief executive officer of Knife River Corporation effective May 1, 2005; and senior vice president-construction materials effective from September 15, 1999 to April 30, 2005.
Doran N. Schwartz	43	Mr. Schwartz was elected vice president and chief financial officer effective February 17, 2010. Prior to that, he was vice president and chief accounting officer effective March 1, 2006; and assistant vice president-special projects effective September 6, 2005. He was director of membership rewards for American Express, a financial services company, from November 2004 to August 1, 2005; audit manager for Deloitte & Touche, an audit and professional services company, from June 2002 to November 2004; and audit manager/senior for Arthur Andersen, an audit and professional services company, from December 1997 to June 2002.
John P. Stumpf	53	Mr. Stumpf was elected vice president–strategic planning effective December 1, 2006. Mr. Stumpf was vice president–corporate development for Knife River Corporation from July 1, 2002 to November 30, 2006, and director of corporate development of Knife River Corporation from January 14, 2002 to June 30, 2002. Prior to that, he was special projects manager for Knife River Corporation from May 1, 2000 to January 13, 2002.
J. Kent Wells	56	Mr. Wells was elected vice chairman of the company and a director effective January 4, 2013, and continues to serve as president and chief executive officer of Fidelity Exploration & Production Company, the position for which he was hired effective May 2, 2011. For more information about Mr. Wells, see "Election of Directors."

SECURITY OWNERSHIP

The table below sets forth the number of shares of our capital stock that each director and each nominee for director, each named executive officer, and all directors and executive officers as a group owned beneficially as of December 31, 2012.

Name	Common Shares Beneficially Owned(1)	Shares Held By Family Members(2)	Percent of Class	Deferred Director Fees Held as Phantom Stock(3)
Steven L. Bietz	69,392(4)		*	
Thomas Everist	1,885,590(5)		1.0	29,243
Karen B. Fagg	37,481		*	
Terry D. Hildestad	214,073		*	
A. Bart Holaday	41,200		*	
Dennis W. Johnson	88,583(6)	4,560	*	
Thomas C. Knudson	24,467		*	
Richard H. Lewis	28,167		*	18,185
Patricia L. Moss	63,225		*	
Harry J. Pearce	218,017		*	48,081
William E. Schneider	104,555(7)	800	*	
Doran N. Schwartz	24,763(4) (8)	1,300	*	
J. Kent Wells	27,743		*	
John K. Wilson	90,549		*	
All directors and executive officers as a group (23 in number)	3,222,078	20,228	1.7	95,509

* Less than one percent of the class.

(1) "Beneficial ownership" means the sole or shared power to vote, or to direct the voting of, a security, or investment power with respect to a security.

(2) These shares are included in the "Common Shares Beneficially Owned" column.

(3) These shares are not included in the "Common Shares Beneficially Owned" column. Directors may defer all or a portion of their cash compensation pursuant to the Deferred Compensation Plan for Directors. Deferred amounts are held as phantom stock with dividend accruals and are paid out in cash over a five-year period after the director leaves the board.

(4) Includes full shares allocated to the officer's account in our 401(k) retirement plan.

(5) Includes 1,820,000 shares of common stock acquired through the sale of Connolly-Pacific to us.

(6) Mr. Johnson disclaims all beneficial ownership of the 4,560 shares owned by his wife.

(7) Mr. Schneider disclaims all beneficial ownership of the 800 shares owned by his wife.

(8) The total includes 1,300 shares owned by Mr. Schwartz's wife.

We prohibit our directors and executive officers from hedging their ownership of company common stock. They may not enter into transactions that allow them to benefit from devaluation of our stock or otherwise own stock technically but without the full benefits and risks of such ownership.

Directors, executive officers, and related persons are prohibited from holding our common stock in a margin account, with certain exceptions, or pledging company securities as collateral for a loan. Company common stock may be held in a margin brokerage account only if the stock is explicitly excluded from any margin, pledge, or security provisions of the customer agreement. Company common stock may be held in a cash account, which is a brokerage account that does not allow any extension of credit on securities. "Related person" means an executive officer's or director's spouse, minor child, and any person (other than a tenant or domestic employee) sharing the household of a director or executive officer, as well as any entities over which a director or executive officer exercises control.

The table below sets forth information with respect to any person we know to be the beneficial owner of more than five percent of any class of our voting securities.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	BlackRock, Inc. 40 East 52nd Street New York, NY 10022	11,808,063(1)	6.25%
Common Stock	T. Rowe Price Associates, Inc. 100 E. Pratt Street Baltimore, MD 21202	11,315,091(2)	5.90%
Common Stock	State Street Corporation State Street Financial Center One Lincoln Street Boston, MA 02111	9,760,389(3)	5.20%
Common Stock	The Vanguard Group 100 Vanguard Blvd. Malvern, PA 19355	10,319,105(4)	5.46%

(1) In a Schedule 13G/A, Amendment No. 3, filed on February 5, 2013, BlackRock, Inc. reports sole voting and dispositive power with respect to all shares as the parent holding company or control person of BlackRock Capital Management, BlackRock Financial Management, Inc., BlackRock Japan Co. Ltd., BlackRock Advisors (UK) Limited, BlackRock Institutional Trust Company, N.A., BlackRock Fund Advisors, BlackRock Asset Management Canada Limited, BlackRock Asset Management Australia Limited, BlackRock Advisors, LLC, BlackRock Investment Management, LLC, BlackRock Investment Management (Australia) Limited, BlackRock Life Limited, BlackRock (Netherlands) B.V., BlackRock Fund Managers Limited, BlackRock Asset Management Ireland Limited, BlackRock International Limited, and BlackRock Investment Management (UK) Limited.

(2) In a Schedule 13G/A, Amendment No. 1, filed on February 7, 2013, T. Rowe Price Associates, Inc. reports sole voting power with respect to 1,724,000 shares and sole dispositive power with respect to 11,315,091 shares. These securities are owned by individual and institutional investors to which T. Rowe Price serves as investment adviser with power to direct investments and/or sole power to vote the securities. For purposes of the reporting requirements of the Securities Exchange Act of 1934, T. Rowe Price is deemed to be a beneficial owner of such securities; however, T. Rowe Price expressly disclaims that it is, in fact, the beneficial owner of such securities.

(3) In a Schedule 13G, filed on February 12, 2013, State Street Corporation reports shared voting and dispositive power with respect to all shares as the parent holding company or control person of State Street Global Advisors France S.A., State Street Bank and Trust Company, SSGA Funds Management, Inc., State Street Global Advisors Limited, State Street Global Advisors Ltd, State Street Global Advisors, Australia Limited, State Street Global Advisors Japan Co., Ltd. and State Street Global Advisors, Asia Limited.

(4) In a Schedule 13G, filed on February 13, 2013, The Vanguard Group reports sole dispositive power with respect to 10,140,265 shares, shared dispositive power with respect to 178,840 shares and sole voting power with respect to 191,340 shares. These shares include 127,440 shares beneficially owned by Vanguard Fiduciary Trust Company, a wholly-owned subsidiary of The Vanguard Group, Inc., as a result of its serving as investment manager of collective trust accounts, and 115,300 shares beneficially owned by Vanguard Investments Australia, Ltd., a wholly-owned subsidiary of The Vanguard Group, Inc., as a result of its serving as investment manager of Australian investment offerings.

RELATED PERSON TRANSACTION DISCLOSURE

The board of directors has adopted a policy for the review of related person transactions. This policy is contained in our corporate governance guidelines, which are posted on our website at www.mdu.com.

The audit committee reviews related person transactions in which we are or will be a participant to determine if they are in the best interests of our stockholders and the company. Financial transactions, arrangements, relationships, or any series of similar transactions, arrangements, or relationships in which a related person had or will have a material interest and that exceed $120,000 are subject to the committee's review.

Related persons are directors, director nominees, executive officers, holders of 5% or more of our voting stock, and their immediate family members. Immediate family members are spouses, parents, stepparents, mothers-in-law, fathers-in-law, siblings, brothers-in-law, sisters-in-law, children, stepchildren, daughters-in-law, sons-in-law, and any person, other than a tenant or domestic employee, who shares the household of a director, director nominee, executive officer, or holder of 5% or more of our voting stock.

After its review, the committee makes a determination or a recommendation to the board and officers of the company with respect to the related person transaction. Upon receipt of the committee's recommendation, the board of directors or officers, as the case may be, take such action as they deem appropriate in light of their responsibilities under applicable laws and regulations.

The audit committee and the board of directors reviewed two leases between an indirect subsidiary of the company and a Nevada limited liability company, MOJO Montana, LLC (MOJO). John G. Harp, who is chief executive officer of MDU Construction Services Group, Inc. and Knife River Corporation, and his brother, Michael D. Harp, are managing members of MOJO. The properties described in these two leases are located in Kalispell and Billings, Montana, and have been leased since 1998. In May 2010, the audit committee determined that renewing these leases was in the company's best interests after it reviewed 2010 third party appraisals for the properties and considered the consumer price index and our operating companies' knowledge of local property markets. The audit committee recommended and the board approved three-year leases for these properties that provide for our indirect subsidiary to pay a combined monthly rent of $9,508 to MOJO. The leases expire June 30, 2013.

CORPORATE GOVERNANCE

Director Independence

The board of directors has adopted guidelines on director independence that are included in our corporate governance guidelines, which are available for review on our corporate website at http://www.mdu.com/Documents/Governance/CorporateGovernance.pdf. The board of directors has determined that Thomas Everist, Karen B. Fagg, A. Bart Holaday, Dennis W. Johnson, Thomas C. Knudson, Richard H. Lewis, Patricia L. Moss, Harry J. Pearce, and John K. Wilson:

- have no material relationship with us and
- are independent in accordance with our director independence guidelines and the New York Stock Exchange listing standards.

In determining director independence for 2012, the board of directors considered the following transactions or relationships:

- Mr. Everist's ownership of approximately 1.87 million shares in 2011 and approximately 1.89 million shares in 2012 of our common stock. In December 2011, we entered into a two-year contract with WebFilings, LLC, which offers a cloud-based solution for meeting SEC reporting requirements. The contract provides for a quarterly subscription fee of approximately $13,000 to use WebFilings' software and for additional fees to be determined based on the number of users and additional services requested. The additional fees for 2011 were $4,500, for 2012 were $5,000, and we expect them to be approximately $3,100 for 2013. Mr. Everist is a limited partner and owns less than 1% of WebFilings, LLC. The MDU Resources Foundation (Foundation) made charitable contributions to Medcenter One Foundation, which is now known as Sanford Health following a merger effective July 2, 2012, in the amount of $500 in 2011 and $1,250 in 2012. Mr. Everist is a member of the board of directors of the Sanford Health Foundation and his wife, Barbara Everist, is vice chairman of the board of trustees of Sanford Health.
- charitable contributions from the Foundation in the amount of $2,700 in 2011 and $2,625 in 2012 to the University of North Dakota Foundation – Mr. Holaday serves as the chairman of the board and as a trustee for the University of North Dakota Center for Innovation Foundation and also serves as a director for the University of North Dakota Foundation; charitable contributions from the Foundation in the amount of $3,750 in 2011 and $27,250 in 2012 to Jamestown College or its foundation – Mr. Holaday serves as a trustee for Jamestown College.
- charitable contributions from the Foundation to the City of Dickinson in the amount of $20,000 in 2011 and 2012 – Mr. Johnson is president of the City of Dickinson board of commissioners.

- charitable contributions from the Foundation to Colorado UpLift in the amount of $25,000 in 2011 and $20,000 in 2012 – Mr. Lewis is a board director and chairman of the Development Board of Colorado UpLift; charitable contributions from the Foundation in the amount of $10,000 in 2011 and $5,000 in 2012 to the Alliance for Choice in Education – Mr. Lewis serves on the Board of Trustees for Alliance.

Director Resignation upon Change of Job Responsibility

Our corporate governance guidelines require a director to tender his or her resignation after a material change in job responsibility. In 2012, no directors submitted resignations under this requirement.

Code of Conduct

We have a code of conduct and ethics, which we refer to as the Leading With Integrity Guide, which applies to all employees, directors, and officers.

We intend to satisfy our disclosure obligations regarding:

- amendments to, or waivers of, any provision of the code of conduct that applies to our principal executive officer, principal financial officer, and principal accounting officer and that relates to any element of the code of ethics definition in Regulation S-K, Item 406(b) and
- waivers of the code of conduct for our directors or executive officers, as required by New York Stock Exchange listing standards by posting such information on our website at http://www.mdu.com/Documents/Governance/IntegrityGuide.pdf.

Board Leadership Structure and Board's Role in Risk Oversight

The board separated the positions of chairman of the board and chief executive officer in 2006 and elected Harry J. Pearce, a non-employee independent director, as our chairman. Separating these positions allows our chief executive officer to focus on the full-time job of running our business, while allowing the chairman of the board to lead the board in its fundamental role of providing advice to and independent oversight of management. The board believes this structure recognizes the time, effort, and energy that the chief executive officer is required to devote to his position in the current business environment, as well as the commitment required to serve as our chairman, particularly as the board's oversight responsibilities continue to grow and demand more time and attention. The fundamental role of the board of directors is to provide oversight of the management of the company in good faith and in the best interests of the company and its stockholders. Having an independent chairman is a means to ensure the chief executive officer is accountable for managing the company in close alignment with the interests of stockholders. An independent chairman avoids the conflicts of interest that arise when the chairman and chief executive positions are combined and more effectively manages relationships between the board and the chief executive officer. An independent chairman is in a better position to encourage frank and lively discussions and to assure that the company has adequately assessed all appropriate business risks before adopting its final business plans and strategies. In August 2012, we amended our bylaws and corporate governance guidelines to require that our chairman be independent. The board believes that having separate positions and having an independent outside director serve as chairman is the appropriate leadership structure for the company and demonstrates our commitment to good corporate governance.

Risk is inherent with every business, and how well a business manages risk can ultimately determine its success. We face a number of risks, including economic risks, environmental and regulatory risks, and others, such as the impact of competition, weather conditions, limitations on our ability to pay dividends, increased pension plan obligations, and cyber attacks or acts of terrorism. Management is responsible for the day-to-day management of risks the company faces, while the board, as a whole and through its committees, has responsibility for the oversight of risk management. In its risk oversight role, the board of directors has the responsibility to satisfy itself that the risk management processes designed and implemented by management are adequate and functioning as designed.

The board believes that establishing the right "tone at the top" and that full and open communication between management and the board of directors are essential for effective risk management and oversight. Our chairman meets regularly with our president and chief executive officer and other senior officers to discuss strategy and risks facing the company. Senior management attends the quarterly board meetings and is available to address any questions or concerns raised by the board on risk management-related and any other matters. Each quarter, the board of directors receives presentations from senior management on strategic matters involving our operations. The board holds strategic planning sessions with senior management to discuss strategies, key challenges, and risks and opportunities for the company.

While the board is ultimately responsible for risk oversight at our company, our three board committees assist the board in fulfilling its oversight responsibilities in certain areas of risk. The audit committee assists the board in fulfilling its oversight responsibilities with respect to risk assessment and management in a general manner and specifically in the areas of financial reporting, internal controls and compliance with legal and regulatory requirements, and, in accordance with New York Stock Exchange requirements, discusses policies with respect to risk assessment and risk management and their adequacy and effectiveness. Risk assessment reports are regularly provided by management to the audit committee. This opens the opportunity for discussions about areas where the company may have material risk exposure, steps taken to manage those exposures, and the company's risk tolerance in relation to company strategy. The audit committee reports regularly to the board of directors on the company's management of risks in the audit committee's areas of responsibility. The compensation committee assists the board in fulfilling its oversight responsibilities with respect to the management of risks arising from our compensation policies and programs. The nominating and governance committee assists the board in fulfilling its oversight responsibilities with respect to the management of risks associated with board organization, membership and structure, succession planning for our directors and executive officers, and corporate governance.

Board Meetings and Committees

During 2012, the board of directors held seven meetings. Each director attended at least 75% of the combined total meetings of the board and the committees on which the director served during 2012. Director attendance at our annual meeting of stockholders is left to the discretion of each director. Three directors attended our 2012 annual meeting of stockholders.

Harry J. Pearce was elected non-employee chairman of the board on August 17, 2006. Mr. Pearce served as lead director from February 15, 2001 to August 17, 2006. He presides at the executive session of the non-employee directors held in connection with each regularly scheduled quarterly board of directors meeting. The non-employee directors also meet in executive session with the chief executive officer at each regularly scheduled quarterly board of directors meeting. All of our non-employee directors are independent directors.

The board has a standing audit committee, compensation committee, and nominating and governance committee. These committees are composed entirely of independent directors.

The audit, compensation, and nominating and governance committees have charters, which are available for review on our website at http://www.mdu.com/Governance/Pages/BoardChartersandCommittees.aspx. Our corporate governance guidelines are available at http://www.mdu.com/Documents/Governance/CorporateGovernance.pdf, and our Leading With Integrity Guide is also on our website at http://www.mdu.com/Documents/Governance/IntegrityGuide.pdf.

Nominating and Governance Committee

The nominating and governance committee met four times during 2012. The committee members were Karen B. Fagg, chairman, Richard H. Lewis, A. Bart Holaday, and Patricia L. Moss.

The nominating and governance committee provides recommendations to the board with respect to:

- board organization, membership, and function
- committee structure and membership
- succession planning for our executive management and directors and
- corporate governance guidelines applicable to us.

The nominating and governance committee assists the board in overseeing the management of risks in the committee's areas of responsibility.

The committee identifies individuals qualified to become directors and recommends to the board the nominees for director for the next annual meeting of stockholders. The committee also identifies and recommends to the board individuals qualified to become our principal officers and the nominees for membership on each board committee. The committee oversees the evaluation of the board and management.

In identifying nominees for director, the committee consults with board members, our management, consultants, and other individuals likely to possess an understanding of our business and knowledge concerning suitable director candidates.

Our corporate governance guidelines include our policy on consideration of director candidates recommended to us. We will consider candidates that our stockholders recommend. Stockholders may submit director candidate recommendations to the nominating and governance committee chairman in care of the secretary at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650. Please include the following information:

- the candidate's name, age, business address, residence address, and telephone number
- the candidate's principal occupation
- the class and number of shares of our stock owned by the candidate
- a description of the candidate's qualifications to be a director
- whether the candidate would be an independent director and
- any other information you believe is relevant with respect to the recommendation.

These guidelines provide information to stockholders who wish to recommend candidates for director for consideration by the nominating and governance committee. Stockholders who wish to actually nominate persons for election to our board at an annual meeting of stockholders must follow the procedures set forth in section 2.08 of our bylaws. You may obtain a copy of the bylaws by writing to the secretary of MDU Resources Group, Inc. at the address above. Our bylaws are also available on our website at http://www.mdu.com/Governance/Pages/CorporateGovernanceGuidelines.aspx. See also the section entitled "2014 Annual Meeting of Stockholders" later in the proxy statement.

There are no differences in the manner by which the committee evaluates director candidates recommended by stockholders and those recommended by other sources.

In evaluating director candidates, the committee considers an individual's:

- background, character, and experience, including experience relative to our company's lines of business
- skills and experience which complement the skills and experience of current board members
- success in the individual's chosen field of endeavor
- skill in the areas of accounting and financial management, banking, general management, human resources, marketing, operations, public affairs, law, technology, and operations abroad
- background in publicly traded companies
- geographic area of residence
- diversity of business and professional experience, skills, gender, and ethnic background, as appropriate in light of the current composition and needs of the board
- independence, including any affiliation or relationship with other groups, organizations, or entities and
- prior and future compliance with applicable law and all applicable corporate governance, code of conduct and ethics, conflict of interest, corporate opportunities, confidentiality, stock ownership and trading policies, and our other policies and guidelines.

As indicated above, when identifying nominees to serve as director, the nominating and governance committee will consider candidates with diverse business and professional experience, skills, gender, and ethnic background, as appropriate, in light of the current composition and needs of the board. The nominating and governance committee assesses the effectiveness of this policy annually in connection with the nomination of directors for election at the annual meeting of stockholders. The composition of the current board reflects diversity in business and professional experience, skills, and gender.

The committee generally will hire an outside firm to perform a background check on potential nominees.

Audit Committee

The audit committee is a separately-designated standing committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934.

The audit committee met eight times during 2012. The audit committee members are Dennis W. Johnson, chairman, A. Bart Holaday, Richard H. Lewis, and John K. Wilson. The board of directors has determined that Messrs. Johnson, Holaday, Lewis, and Wilson are "audit committee financial experts" as defined by Securities and Exchange Commission regulations and Messrs. Johnson, Holaday, Lewis, and Wilson meet the independence standard for audit committee members under our director independence guidelines and the New York Stock Exchange listing standards, including the Securities and Exchange Commission's audit committee member independence requirements.

The audit committee assists the board of directors in fulfilling its oversight responsibilities to the stockholders and serves as a communication link among the board, management, the independent auditors, and the internal auditors. The audit committee:

- assists the board's oversight of
  - the integrity of our financial statements and system of internal controls
  - our compliance with legal and regulatory requirements
  - the independent auditors' qualifications and independence
  - the performance of our internal audit function and independent auditors and
  - risk management in the audit committee's areas of responsibility and
- arranges for the preparation of and approves the report that Securities and Exchange Commission rules require we include in our annual proxy statement.

Audit Committee Report

In connection with our financial statements for the year ended December 31, 2012, the audit committee has (1) reviewed and discussed the audited financial statements with management; (2) discussed with the independent auditors the matters required to be discussed by the statement on Auditing Standards No. 61, as amended, (AICPA, *Professional Standards*, Vol. 1, AU section 380), as adopted by the Public Company Accounting Oversight Board in Rule 3200T; (3) received the written disclosures and the letter from the independent accountant required by applicable requirements of the Public Company Accounting Oversight Board regarding the independent accountant's communications with the audit committee concerning independence, and has discussed with the independent accountant the independent accountant's independence.

Based on the review and discussions referred to in items (1) through (3) of the above paragraph, the audit committee recommended to the board of directors that the audited financial statements be included in our Annual Report on Form 10-K for the year ended December 31, 2012, for filing with the Securities and Exchange Commission.

Dennis W. Johnson, Chairman
A. Bart Holaday
Richard H. Lewis
John K. Wilson

Compensation Committee

The compensation committee met five times during 2012. The compensation committee members are Thomas Everist, chairman, Karen B. Fagg, Thomas C. Knudson, and Patricia L. Moss.

The compensation committee's responsibilities, as set forth in its charter, include:

- review and recommend changes to the board regarding our executive compensation policies for directors and executives
- evaluate the chief executive officer's performance and, either as a committee or together with other independent directors as directed by the board, determine his or her compensation
- recommend to the board the compensation of our other Section 16 officers and directors
- establish goals, make awards, review performance and determine, or recommend to the board, awards earned under our annual and long-term incentive compensation plans
- review and discuss with management the compensation discussion and analysis and based upon such review and discussion, determine whether to recommend to the board that the Compensation Discussion and Analysis be included in our proxy statement and/or our Annual Report on Form 10-K
- arrange for the preparation of and approve the compensation committee report to be included in our proxy statement and/or Annual Report on Form 10-K and
- assist the board in overseeing the management of risk in the committee's areas of responsibility.

The compensation committee and the board of directors have sole and direct responsibility for determining compensation for our Section 16 officers and directors. The compensation committee makes recommendations to the board regarding compensation of all Section 16 officers, and the board then approves the recommendations. The compensation committee and the board may not delegate their authority. They may, however, use recommendations from outside consultants, the chief executive officer, and the human resources department. The chief executive officer, the vice president-human resources, and general counsel regularly attend compensation committee meetings. The committee meets in executive session as needed. The committee's practice has been to retain a compensation consultant every other year to conduct a competitive analysis on executive compensation. The committee retained a compensation consultant in 2012 to prepare a competitive assessment for 2013 compensation for our Section 16 officers.

We discuss our processes and procedures for consideration and determination of compensation of our Section 16 officers in the Compensation Discussion and Analysis. We also discuss in the Compensation Discussion and Analysis the role of our executive officers in determining or recommending compensation for our Section 16 officers.

During 2012, the compensation committee retained Towers Watson to prepare the 2013 competitive assessment covering our Section 16 officers. In an engagement letter dated March 23, 2012, the compensation committee asked Towers Watson to prepare separate executive compensation reviews for the Section 16 officers and for the chief executive officer. In its review for the Section 16 officers, excluding the chief executive officer, Towers Watson was asked to:

- match the Section 16 officer positions to survey data to generate 2013 market estimates for base salaries and short-term and long-term incentives
- address general trends in executive compensation
- compare base salaries and target short-term and long-term incentives, by position, to market estimates and recommend salary grade changes as appropriate
- construct a recommended 2013 salary grade structure
- verify the competitiveness of short-term and long-term incentive targets associated with salary grades and recommend modifications as appropriate.

In the chief executive officer review, Towers Watson was asked to use survey data and data from the company's performance graph peer group to:

- develop competitive estimates for base salary and target short-term and long-term incentives
- recommend changes in base salary and incentive targets based on the competitive data and
- address general trends in chief executive officer compensation.

The compensation committee has sole authority to retain, discharge, and approve fees and other terms and conditions for retention of compensation consultants to assist in consideration of the compensation of the chief executive officer, the other Section 16 officers, and the board of directors. The compensation committee charter requires the committee's pre-approval of the engagement of the committee's compensation consultants by the company for any other purpose. The compensation committee authorized the company to participate in compensation and employee benefits surveys sponsored by Towers Watson in 2012.

The compensation committee requested and received information from its compensation consultant, Towers Watson, to assist the committee in determining whether Towers Watson's work raised any conflict of interest. The compensation committee has reviewed Towers Watson's responses to its request and determined that the work of Towers Watson did not raise any conflict of interest in 2012.

The board of directors determines compensation for our non-employee directors based upon recommendations from the compensation committee. The compensation committee's practice has been to retain a compensation consultant every other year to conduct a competitive analysis on director compensation. The compensation committee did not retain an outside consultant for the 2012 compensation review for the board of directors. At its May 2012 meeting, the committee reviewed the analysis of competitive data and recent trends in director compensation, including independent chairman of the board compensation, prepared by the human resources department and the vice president-human resources. The company's analysis was based on proxy data from our performance graph peer group companies compiled by Equilar and on data from the National Association of Corporate Directors 2011/2012 Director Compensation Report. The committee compared the data to our directors' compensation and each of its components. After review and discussion of the market data, which indicated that our median director compensation of $165,000 was below the median total direct compensation of $179,596 for large companies in the National Association of Corporate Directors 2011/2012 Director Compensation Report and consistent with the median total direct compensation of $162,002 of the peer companies, the compensation committee recommended, and the board approved, that no changes be made to director compensation for 2012. With respect to non-executive chairman of the board compensation comparison to other directors, the multiple of the median non-executive director total pay for the company was 1.45X as compared to 1.64X under the National Association of Corporate Directors 2011/2012 Director Compensation Report companies and 1.84X for the peer companies. The compensation committee recommended, and the board approved, that no changes be made to the non-executive chairman of the board compensation for 2012.

Stockholder Communications

Stockholders and other interested parties who wish to contact the board of directors or an individual director, including our non-employee chairman or non-employee directors as a group, should address a communication in care of the secretary at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650. The secretary will forward all communications.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16 of the Securities Exchange Act of 1934, as amended, requires that officers, directors, and holders of more than 10% of our common stock file reports of their trading in our equity securities with the Securities and Exchange Commission. Based solely on a review of Forms 3, 4, and 5 and any amendments to these forms furnished to us during and with respect to 2012 or written representations that no Forms 5 were required, we believe that all such reports were timely filed, except that one Form 4 for Mr. Lewis reporting one transaction was filed one week late.

CONDUCT OF MEETING; ADJOURNMENT

The chairman of the board has broad responsibility and authority to conduct the annual meeting in an orderly and timely manner. In addition, our bylaws provide that the meeting may be adjourned from time to time by the chairman of the meeting regardless of whether a quorum is present.

OTHER BUSINESS

Neither the board of directors nor management intends to bring before the meeting any business other than the matters referred to in the notice of annual meeting and this proxy statement. We have not been informed that any other matter will be presented at the meeting by others. However, if any other matters are properly brought before the annual meeting, or any adjournment(s) thereof, your proxies include discretionary authority for the persons named in the enclosed proxy to vote or act on such matters in their discretion.

SHARED ADDRESS STOCKHOLDERS

In accordance with a notice sent to eligible stockholders who share a single address, we are sending only one annual report to stockholders and one proxy statement to that address unless we received instructions to the contrary from any stockholder at that address. This practice, known as “householding,” is designed to reduce our printing and postage costs. However, if a stockholder of record wishes to receive a separate annual report to stockholders and proxy statement in the future, he or she may contact the office of the treasurer at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650, Telephone Number: (701) 530-1000. Eligible stockholders of record who receive multiple copies of our annual report to stockholders and proxy statement can request householding by contacting us in the same manner. Stockholders who own shares through a bank, broker, or other nominee can request householding by contacting the nominee.

We hereby undertake to deliver promptly, upon written or oral request, a separate copy of the annual report to stockholders and proxy statement to a stockholder at a shared address to which a single copy of the document was delivered.

2014 ANNUAL MEETING OF STOCKHOLDERS

Director Nominations: Our bylaws provide that director nominations may be made only by (i) the board at any meeting of stockholders or (ii) at an annual meeting by a stockholder entitled to vote for the election of directors and who has complied with the procedures established by the bylaws. For a nomination to be properly brought before an annual meeting by a stockholder, the stockholder intending to make the nomination must have given timely and proper notice of the nomination in writing to the corporate secretary in accordance with and containing all information and the completed questionnaire provided for in the bylaws. To be timely, such notice must be delivered to or mailed to the corporate secretary and received at our principal executive offices not later than 90 days prior to the first anniversary of the preceding year’s annual meeting of stockholders. For purposes of our annual meeting of stockholders expected to be held April 22, 2014, any stockholder who wishes to submit a nomination must submit the required notice to the corporate secretary on or before January 23, 2014.

Other Meeting Business: Our bylaws also provide that no business may be brought before an annual meeting except (i) as specified in the meeting notice given by or at the direction of the board, (ii) as otherwise properly brought before the meeting by or at the direction of the board or (iii) properly brought before the meeting by a stockholder entitled to vote who has complied with the procedures established by the bylaws. For business to be properly brought before an annual meeting by a stockholder (other than nomination of a person for election as a director which is described above) the stockholder must have given timely and proper notice of such business in writing to the corporate secretary, in accordance with, and containing all information provided for in the bylaws and such business must be a proper matter for stockholder action under the General Corporation Law of Delaware. To be timely, such notice must be delivered or mailed to the corporate secretary and received at our principal executive offices not later than the close of business 90 days prior to the first anniversary of the preceding year’s annual meeting of stockholders. For purposes of our annual meeting expected to be held April 22, 2014, any stockholder who wishes to bring business before the meeting (other than nomination of a person for election as a director which is described above) must submit the required notice to the corporate secretary on or before January 23, 2014.

Discretionary Voting: Rule 14a-4 of the Securities and Exchange Commission’s proxy rules allows us to use discretionary voting authority to vote on matters coming before an annual stockholders’ meeting if we do not have notice of the matter at least 45 days before the anniversary date on which we first mailed our proxy materials for the prior year’s annual stockholders’ meeting or the date specified by an advance notice provision in our bylaws. Our bylaws contain an advance notice provision that we have described above. For our annual meeting of stockholders expected to be held on April 22, 2014, stockholders must submit such written notice to the corporate secretary on or before January 23, 2014.

Stockholder Proposals: The requirements we describe above are separate from and in addition to the Securities and Exchange Commission's requirements that a stockholder must meet to have a stockholder proposal included in our proxy statement under Rule 14a-8 of the Exchange Act. For purposes of our annual meeting of stockholders expected to be held on April 22, 2014, any stockholder who wishes to submit a proposal for inclusion in our proxy materials must submit such proposal to the corporate secretary on or before November 13, 2013.

Bylaw Copies: You may obtain a copy of the full text of the bylaw provisions discussed above by writing to the corporate secretary. Our bylaws are also available on our website at: http://www.mdu.com/Governance/Pages/CorporateGovernanceGuidelines.aspx.

We will make available to our stockholders to whom we furnish this proxy statement a copy of our Annual Report on Form 10-K, excluding exhibits, for the year ended December 31, 2012, which is required to be filed with the Securities and Exchange Commission. You may obtain a copy, without charge, upon written or oral request to the Office of the Treasurer of MDU Resources Group, Inc., 1200 West Century Avenue, Mailing Address: P.O. Box 5650, Bismarck, ND 58506-5650, Telephone Number: (701) 530-1000. You may also access our Annual Report on Form 10-K through our website at www.mdu.com.

By order of the Board of Directors,

Paul K. Sandness
Secretary
March 13, 2013

EXHIBIT A

Towers Watson 2010 General Industry Executive Compensation Database

3M
7-Eleven
A&P
A.H. Belo
A.O. Smith
A. T. Cross
AAA Northern California, Nevada & Utah
AAA of Science
Abbott Laboratories
ABC
Accenture
ACH Food
Acuity Brands
AEGON
AEI Services
Aeropostale
AFLAC
Agilent Technologies
Agrium
AIG
Air Liquide
Air Products and Chemicals
Alcatel-Lucent
Alcoa
Alcon Laboratories
Alexander & Baldwin
Allegheny Energy
Allergan
Allete
Alliant Energy
Alliant Techsystems
Allianz
Allstate
Allured Business Media
Amazon.com
Ameren
American Chemical Society
American Crystal Sugar
American Electric Power
American Express
American Family Insurance
American United Life
American Water Works
Ameriprise Financial
Ameritrade
Ameron
AMETEK
Amgen
Anadarko Petroleum
Ann Taylor Stores
AOL
APL
Appleton Papers
Applied Materials
ARAMARK
Archer Daniels Midland
Arctic Cat
Areva
Armstrong World Industries
Arrow Electronics
AstraZeneca
AT&T
ATC Management
Atmos Energy
Aurora Healthcare
Auto Club Group
Automatic Data Processing
Avanade
Avis Budget Group
Avista
AXA Group
B&W Technical Services Y-12
Ball
Bank of America
Bank of Hawaii
Bank of New York Mellon
Bank of the West
Barnes Group
Barrick Gold of North America
Baxter International
Bayer AG
Bayer CropScience
Bayer MaterialScience
BB&T
BBVA
BD
Beckman Coulter
Belo
Bemis
Best Buy
BG US Services
Big Lots
Bill & Melinda Gates Foundation
Biogen Idec
BJ's Wholesale Club
Black Hills Power and Light
Blockbuster
Blue Cross Blue Shield of Florida
Blyth
Boehringer Ingelheim
Boeing
BOK Financial
Boston Scientific
Bovis Lend Lease
BP
Brady
Bremer Financial
Bristol-Myers Squibb
Broadcom
Burlington Northern Santa Fe
Bush Brothers
C.H. Robinson Worldwide
CA
Cablevision Systems
Cabot
Cadbury
Calgon Carbon
California Independent System Operator
Callaway Golf
Calpine
Cameron International
Capital One Financial
Capitol Broadcasting – WRAL
Cardinal Health
Career Education
CareFusion
Cargill
Carlson Companies
Carnival
Carpenter Technology
Catalent Pharma Solutions
Catholic Healthcare West
Cedar Rapids TV
Celgene
Cemex
CenterPoint Energy
CenturyLink
Cephalon
CF Industries
CH Energy Group
CH2M Hill
Chemtura
Chevron
Chevron Phillips Chemical
Chiquita Brands
Choice Hotels International
CHS
CIGNA
Cimarex Energy
Cintas
Cisco Systems
CIT Group
Cleco
Cliffs Natural Resources
CMS Energy
CNA
COACH
Cobank
Coca-Cola
Colgate-Palmolive
Colorado Springs Utilities
Columbia Sportswear
Comcast
Comerica
Commerce Bancshares
Commerce Insurance
ConAgra Foods
Connell Limited Partnership
ConocoPhillips
Conseco
Consolidated Edison
Constellation Energy
Consumers Union
Continental Automotive Systems
ConvaTec
Convergys
Cooper Industries
Corning
Covance
Covanta Holdings
Covidien
Cox Enterprises
CPS Energy
Cracker Barrel Old Country Stores
Crown Castle
Crump Group
CSR
CSX
CUNA Mutual
CVS Caremark
Cytec
Daiichi Sankyo
Dana
Dannon
Darden Restaurants
Day & Zimmermann
DCP Midstream
Dean Foods
Del Monte Foods
Dell
Delta Air Lines
Deluxe
Denny's
Dentsply
Devon Energy
Devry
Dex One
Diageo North America
Dionex
Direct Energy
Disney Publishing Worldwide

PROXY

Dominion Resources
Domtar
Donaldson
Dow Chemical
Dow Corning
Dow Jones
DPL
DTE Energy
Duke Energy
DuPont
E.ON U.S.
E.W. Scripps
Eastman Chemical
Eaton
Ecolab
Edison International
Education Management
Eisai
El Paso Corporation
Electric Power Research Institute
Eli Lilly
EMC
EMCOR Group
Emergency Medical Services
EMI Music
Enbridge Energy
Energen
Energy Future Holdings
Energy Northwest
Entergy
EPCO
Epson
Equifax
Equity Office Properties
ERCOT
Erie Insurance
Ernst & Young
ESPN
Essilor of America
Evening Post Publishing – KOAA
Evergreen Packaging
Evonik Degussa
Exelon
Express Scripts
Exterran
ExxonMobil
Fair Isaac
Fairchild Controls
FANUC Robotics America
Farmers Group
Federal Home Loan Bank of San Francisco
Federal Reserve Bank of Atlanta
Federal Reserve Bank of Cleveland
Federal Reserve Bank of Dallas
Federal Reserve Bank of Philadelphia
Federal Reserve Bank of San Francisco
Federal Reserve Bank of St. Louis
Ferderal-Mogul
Ferrellgas
Fidelity Investments
Fidelity National Information Services
Fifth Third Bancorp
Fireman's Fund Insurance
First Horizon National
First Solar
FirstEnergy
Fiserv
Fisher Communications
Flowserve
Fluor
Ford
Forest Laboratories
Fortune Brands
Forum Communications – WDAY
Fox Networks Group
FPL Group
Franklin Resources
Freddie Mac
Freedom Communications
Freeport-McMoRan Copper & Gold
Future US
GAF Materials
Gannett
Gap
GATX
Gavilon
GDF SUEZ Energy North America
General Atomics
General Dynamics
General Electric
General Mills
General Motors
Genworth Financial
Genzyme
Getty Images
Gilead Sciences
GlaxoSmithKline
GMAC Financial Services
Goodrich
Goodyear Tire & Rubber
Google
Gorton's
Graco
Great-West Life Annuity
Greif
Gruma
Grupo Ferrovial
GSM Association
GTECH
Guardian Life
Guideposts
GXS
H&R Block
H.B. Fuller
H.J. Heinz
Hanesbrands
Hannaford
Harland Clarke
Harley-Davidson
Harris Bank
Harris Enterprises
Harry Winston
Hartford Financial Services
Hasbro
Hawaiian Electric
HBO
HCA Healthcare
HD Supply
Health Net
Healthways
Henkel of America
Henry Ford Health Systems
Herman Miller
Hershey
Hertz
Hess
Hewlett-Packard
Highmark Blue Cross Blue Shield
Hilton Worldwide
Hitachi Data Systems
HNI
HNTB
Hoffmann-La Roche
Home Shopping Network
Honeywell
Horizon Blue Cross Blue Shield of New Jersey
Hormel Foods
Hospira
Houghton Mifflin Harcourt Publishing
HR Access
HSBC Holdings
Hubbard Broadcasting
Humana
Hunt Consolidated
Huntington Bancshares
Huntsman
Husky Injection Molding Systems
Hyatt Hotels
IBM
IDACORP
IDEXX Laboratories
IKON Office Solutions
IMS Health
Independence Blue Cross
Infragistics
ING
Integrys Energy Group
Intel
Intercontinental Hotels
International Data
International Flavors & Fragrances
International Paper
Invensys Controls
ION Geophysical
Iron Mountain
Irvine Company
Irving Oil Commercial G.P
ISO New England
iSoft
ISP
ITT – Corporate
J. Crew
J.C. Penney Company
J.M. Smucker
J.R. Simplot
Jabil Circuit
Jack in the Box
Jacobs Engineering
JM Family
John Hancock
Johnson & Johnson
Johnson Controls
Journal Broadcast Group
Kaiser Foundation Health Plan
Kalmbach Publishing
Kaman Industrial Technologies
Kao Brands
KBR
Kellogg
KeyCorp
Kimberly-Clark
Kinder Morgan
Kindred Healthcare
King Pharmaceuticals
Kinross Gold
KLA-Tencor
Knowles Electronics
Koch Industries
Kohler
Kohl's
KPMG
L.L. Bean
L-3 Communications
Lafarge North America
Lance
Land O'Lakes
Lanxess
Laureate Education
Lear
Leggett and Platt
LES
Level 3 Communications
Levi Strauss
Liberty Mutual

Life Technologies
Lincoln Financial
Lockheed Martin
Loews
LOMA
Lorillard Tobacco
Lower Colorado River Authority
LPL Financial
Lyondell Chemical
M&T Bank
MAG Industrial Automation Systems
Magellan Midstream Partners
Marathon Oil
Marriott International
Marsh & McLennan
Marshall & Ilsley
Martin Marietta Materials
Mary Kay
Masco
Massachusetts Mutual
MasterCard
Mattel
Matthews International
McClatchy
McDermott
McDonald's
McGraw-Hill
McKesson
MDU Resources
MeadWestvaco
Mecklenburg County
Media General
Media Tec Publishing
Medicines Company
MedImmune
Medtronic
Merck & Co
Meredith
MetLife
Microsoft
Midwest Independent
Transmission System Operator
Milacron
Millennium Inorganic Chemicals
Millipore
Mine Safety Appliances
Mirant
Mizuno USA
Molson Coors Brewing
Molycorp Minerals
MoneyGram International
Monsanto
Moody's
Morgan Murphy Stations – WISC
Mosaic
Motorola
Munich Re Group
Murphy Oil
MWH Global
Nash-Finch
Nation
National Geographic Society
National Renewable Energy Laboratory
National Starch Polymers Group
Nationwide
Navistar International
Navy Federal Credit Union
Naylor
NBC Universal
NCCI Holdings
Nestle USA
NetJets
New York Independent System Operator
New York Life
New York Power Authority
New York Times
New York University
Newmont Mining
NewPage
Nicor
Nielsen Expositions
NIKE
Nissan North America
Nokia
Noranda Aluminum
Norfolk Southern
Northeast Utilities
Northern Power Systems
Northrop Grumman
Northstar Travel Media
NorthWestern Energy
Northwestern Mutual
NOVA Chemicals
Novartis
Novartis Consumer Health
Novell
Novo Nordisk Pharmaceuticals
NRG Energy
NSTAR
NV Energy
NW Natural
NXP Semi-Conductor
Nycomed US
Nypro
Occidental Chemical
Occidental Petroleum
Office Depot
OGE Energy
Oglethorpe Power
Oklahoma Today Magazine
Omaha Public Power
Omgeo
OneBeacon Insurance
Open Text USA
Orange Business Services
Oshkosh
Owens Corning
Owens-Illinois
Pacific Gas & Electric
Pacific Life
Parametric Technology
Parker Hannifin
Parsons
Pearson
PennWell
Penton Media
People's Bank
Pepco Holdings
PepsiCo
PerkinElmer
Pervasive Software
PetSmart
Pfizer
Phillips-Van Heusen
Phoenix Companies
Pinnacle West Capital
Pitney Bowes
Pittsburgh Corning
PJM Interconnection
PlainsCapital
Plexus
PNC Financial Services
PNM Resources
Polaris Industries
Polymer Group
PolyOne
Portland General Electric
Potash
PPG Industries
PPL
Praxair
Premera Blue Cross
Principal Financial
PrivateBancorp
Progress Energy
Progressive Corporation
Proliance Energy
Protective Life
Providence Health & Services
Prudential Financial
Public Service Enterprise Group
Puget Energy
Pulte Homes
Purdue Pharma
QUALCOMM
Quest Diagnostics
Quintiles
R.R. Donnelley
Ralcorp Holdings
Razorfish
RBC – US
Reader's Digest
Realogy
Redcats USA
Reddy Ice
Redknee Solutions
Reed Business
Regency Energy Partners LP
Regions Financial
Research in Motion
Revlon
RF Micro Devices
RGA Reinsurance Group
Rio Tinto
Roche Diagnostics
Rockwell Automation
Rockwell Collins
Rodale Press
RRI Energy
Ryder System
S.C. Johnson
Safety-Kleen Systems
SAIC
Salt River Project
SanDisk
Sanofi Pasteur
Sanofi-Aventis
Santee Cooper
Sarkes Tarzian – KTVN
Sarkes Tarzian – WRCB
SAS Institute
Saturday Evening Post
Saudi Arabian Oil
Savannah River Nuclear Solutions
Savannah River Remediation
SCA Americas
SCANA
Schlumberger
School Specialty
Schreiber Foods
Schurz – KYTV
Schurz – WDBJ
Schwan's
Scripps Networks Interactive
Seagate Technology
Sealed Air
Securian Financial Group
Security Benefit Group
Sempra Energy
Sensata Technologies
Sensient Technologies
Shell Oil
Sherwin-Williams
Shire Pharmaceuticals
Siemens

Simpson Manufacturing
Sinclair Broadcast Group
Sirius XM Radio
Skype
SLM
Smith & Nephew
Smurfit-Stone Container
Snap-on
Sodexo
Solutia
Solvay America
Sonoco Products
Sony Corporation
SourceMedia
Southern Company Services
Southern Maryland Electric Cooperative
Southern Union Company
Southwest Power Pool
Spectra Energy
Spirit AeroSystems
Sprint Nextel
SPX
SRA International
Stanford University
Stantec
Starbucks
StarTek
Starwood Hotels & Resorts
State Farm Insurance
State Street
Steelcase
Sterling Bancshares
Stop & Shop
STP Nuclear Operating
Stryker
Sun Life Financial
SunTrust
Sunflower Broadcasting
Sunoco
Sunrise Senior Living
SuperMedia
Swagelok
Sybron Dental Specialties
Synacor
Takeda Pharmaceutical Company Limited
Targa Resources
Target
Taubman Centers
TD Bank Financial Group
Telefonica O2
Tellabs
Temple-Inland
Tenet Healthcare
Tennessee Valley Authority
Teradata
Terex
Tesoro
Texas Petrochemicals
Textron
Thermo Fisher Scientific
Thomas & Betts
Thomas Publishing
Thomson Reuters
Thrivent Financial for Lutherans
TIAA-CREF
Time
Time Warner
Time Warner Cable
Timken
T-Mobile USA
Toro
Total System Services
TransCanada
TransUnion
Travelers
Trinity Industries
Tronox
TRW Automotive
T-Systems
TUI
Tupperware
Twin Cities Public Television – TPT
Tyco Electronics
U.S. Bancorp
U.S. Foodservice
UIL Holdings
Unifi
Unilever United States
Union Bank of California
Union Pacific
UniSource Energy
Unisys
United Airlines
United Parcel Service
United Rentals
United States Cellular
United States Steel
United Technologies
United Water
UnitedHealth
Unitil
University of Texas –
M.D. Anderson Cancer Center
Unum Group
USAA
USG
Valero Energy
Vectren
Verde Realty
Verizon
Vertex Pharmaceuticals
VF
Viacom
Village Farms
Visa
Vision Service Plan
Vistar
Visteon
Volvo Group North America
Vulcan
Vulcan Materials
VWR International
Walt Disney
Warnaco
Washington Post
Waste Management
Watson Pharmaceuticals
Watts Water Technologies
Webster Bank
Wellcare Health Plans
Wellpoint
Wells Fargo
Wendy's/Arby's Group
Westar Energy
Western Digital
Westinghouse Electric
Weyerhaeuser
Whirlpool
Whole Foods Market
Wisconsin Energy
Wm. Wrigley Jr.
Wolters Kluwer
Wray Edwin – KTBS
Wyndham Worldwide
Xcel Energy
Yahoo!
Yankee Publishing
YRC Worldwide
Yum! Brands
Zale

Towers Watson 2010 Energy Industry Executive Compensation Database

AEI Services
Allegheny Energy
Allete
Alliant Energy
Ameren
American Electric Power
Areva
ATC Management
Atmos Energy
Avista
BG US Services
Black Hills Power and Light
California Independent System Operator
Calpine
CenterPoint Energy
CH Energy Group
Cleco
CMS Energy
Colorado Springs Utilities
Consolidated Edison
Constellation Energy
Covanta Holdings
CPS Energy
DCP Midstream
Direct Energy
Dominion Resources
DPL
DTE Energy
Duke Energy
E.ON U.S.
Edison International
El Paso Corporation
Electric Power Research Institute
Enbridge Energy
Energen
Energy Future Holdings
Energy Northwest
Entergy
EPCO
ERCOT
Exelon
First Solar
FirstEnergy
FPL Group
GDF SUEZ Energy North America
Hawaiian Electric
IDACORP
Integrys Energy Group
ISO New England
Kinder Morgan
LES
Lower Colorado River Authority
MDU Resources
Midwest Independent Transmission System Operator
Mirant
New York Independent System Operator
New York Power Authority
Nicor
Northeast Utilities
NorthWestern Energy
NRG Energy
NSTAR
NV Energy
NW Natural
OGE Energy
Oglethorpe Power
Omaha Public Power
Pacific Gas & Electric
Pepco Holdings

Pinnacle West Capital
PJM Interconnection
PNM Resources
Portland General Electric
PPL
Progress Energy
Proliance Holdings
Public Service Enterprise Group
Puget Energy
Regency Energy Partners LP
RRI Energy
Salt River Project
Santee Cooper
SCANA
Sempra Energy
Southern Company Services
Southern Maryland Electric Cooperative
Southern Union Company
Southwest Power Pool
Spectra Energy
STP Nuclear Operating
Targa Resources
Tennessee Valley Authority
TransCanada
UIL Holdings
UniSource Energy
Unitil
Vectren
Westar Energy
Westinghouse Electric
Wisconsin Energy
Wolf Creek Nuclear
Xcel Energy

Effective Compensation, Inc.'s 2010 Oil & Gas Compensation Survey

ANKOR Energy LLC
Antero Resources
Approach Resources Inc.
Aspect Holdings, LLC
Atinum E&P, Inc.
Atlas Energy Resources L.L.C.F
Berry Petroleum Company
Bill Barrett Corporation
Black Hills Corporation
BOPCO, L.P.
BreitBurn Energy Partners LP
Brigham Exploration Company
Browning Oil Company, Inc.
BTA Oil Producers, LLC
Cabot Oil & Gas Corporation
Cano Petroleum, Inc.
Carrizo Oil & Gas Inc.
Ceja Corporation
Chaparral Energy, L.L.C.
Chesapeake Energy Corporation
Cimarex Energy Co.
Comstock Resources
Cohort Energy Company (J-W Operating)
Concho Resources, Inc.
Consol Energy Inc.
Continental Resources, Inc.
Crimson Exploration, Inc.
Denbury Resources, Incorporated
Devon Energy Corporation
Duncan Oil, Inc.
Dynamic Offshore Resources, LLC
Eagle Rock Energy
EnCana Oil & Gas
Energen Resources Corporation
Energy Partners, Ltd.
Eni Petroleum Co. Inc.
EOG Resources Inc
EQT Corporation
Equal Energy US Inc. (Altex Energy)
EXCO Resources, Inc.
Fasken Oil and Ranch, Ltd.
Fidelity Exploration & Production
FIML Natural Resources
Forest Oil Corporation
GMX Resources Inc.
Goodrich Petroleum Company of Louisiana
Great Western Drilling Company
Harvest Natural Resources, Inc.
Henry Resources LLC
HighMount Exploration & Production, LLC
Hilcorp Energy Company
Hillwood International Energy
Holmes Western Oil Corporation
J. M. Huber Corporation
Kinder Morgan CO2 Company L.P.
Lake Ronel Oil Company
Leed Petroleum LLC
Linn Operating, Inc.
Manti Resources
Mariner Energy, Inc.
Maritech Resources, Inc.
McElvain Oil & Gas Properties, Inc.
McMoran Oil and Gas Company
Medco Petroleum Management LLC
Merit Energy Company
Mewbourne Oil Company
Murchison Oil & Gas Inc.
Mustang Fuel Corporation
Nations Petroleum Company Ltd.
Nearburg Producing Company
Newfield Exploration Company
Nexen Petroleum U.S.A., Inc.
NFR Energy LLC
Noble Energy, Inc.
Oasis Petroleum
Oxy Long Beach, Inc. (Thums Long Beach)
Panhandle Oil and Gas Inc.
PDC Energy (Petroleum Development Corporation)
Penn Virginia Corporation
Petroglyph Energy, Inc.
Petrohawk Energy Corporation
Petro-Hunt, LLC
PetroQuest Energy, Inc.
Phoenix Exploration Company
Pioneer Natural Resources Company
Plains Exploration & Production Company
QEP Resources, Inc. (Questar Market Resources)
Quantum Resources Management, LLC
Quicksilver Resources Inc.
Range Resources Corporation
Read & Stevens, Inc.
Resolute Energy Corporation
Rex Energy Corporation
Rosetta Resources, Inc.
Samson
Seneca Resources Corporation
Sheridan Production Company
Sinclair Services Company
Southwestern Energy Production Company
St. Mary Land & Exploration Company
Stone Energy Corporation
Summit Petroleum LLC
Swift Energy Company
Talisman Energy USA Inc. (Fortuna)
T-C Oil Company
Tema Oil and Gas Company
Total E&P USA, Inc.
Triad Energy Corporation
Tri-Valley Corporation
Ultra Petroleum Corporation
Vantage Energy L.L.C
Venoco, Inc.
Vernon E. Faulconer, Inc.
Wagner & Brown, Ltd.
Walter Duncan, Inc.
Whiting Petroleum Corporation
Williams
Woodside Energy
Wynn-Crosby
XTO Energy Inc.
Yuma Exploration & Production Company, Inc.

Mercer's 2010 Total Compensation Survey for the Energy Sector

AGL Resources
AGL Resources – Sequent Energy Management
Abraxas Petroleum Corporation
Aera Energy, LLC
Aker Solutions
Alliance Pipeline
Alyeska Pipeline Service Company
Ameren Corporation
Ameren Corporation – AmerenEnergy Fuels & Services
Ameren Corporation – AmerenEnergyResources
Ameren Corporation – AmerienIllinois
Ameren Corporation – AmerenUE
American Transmission Company
Apache Corporation
Arch Coal, Inc.
Associated Electric Cooperative, Inc.
Atlas Energy, Inc.
BG US Services
BHP Billiton Petroleum (Americas), Inc.
Baker Hughes, Inc.
Baker Hughes, Inc. – Baker Atlas
Baker Hughes, Inc. – Baker Hughes Drilling Fluids
Baker Hughes, Inc. – Baker Hughes Inteq
Baker Hughes, Inc. – Baker Oil Tools
Baker Hughes, Inc. – Baker Petrolite
Baker Hughes, Inc. – Centrilift
Baker Hughes, Inc. – Gaffney, Cline & Associates
Baker Hughes, Inc. – GeoMechanics International
Baker Hughes, Inc. – Hughes Christensen
Baker Hughes, Inc. – Production Quest
Basic Energy Services
Baytex Energy USA Ltd.
Boardwalk Pipeline Partners, LP
BreitBurn Energy Partners L.P.
BreitBurn Energy Partners L.P. – Eastern Division
BreitBurn Energy Partners L.P. – Orcutt Facility
BreitBurn Energy Partners L.P. – West Pico Facility
BreitBurn Energy Partners L.P. – Western Division
BreitBurn Energy Partners L.P. – Western Division, California Operations
BreitBurn Energy Partners L.P. – Western Division, Florida Operations
BreitBurn Energy Partners L.P. – Western Division, Wyoming Operations
Brigham Exploration Company
Brookfield Renewable Power

Buckeye Partners, L.P.
Burnett Oil Co., Inc.
CCS Midstream Service, LLC
CEDA International Inc.
CGGVeritas
CHS Inc. – Energy
CITGO Petroleum Corporation
CPS Energy
Calfrac Well Services Corporation
California ISO
Cameron International
Cameron International – Aftermarket
Cameron International – Centrifugal
Cameron International – Compression Systems
Cameron International – Distributor Valves Division
Cameron International – Drilling Systems
Cameron International – Drilling and Production Systems
Cameron International – Engineered Valves Divison
Cameron International – Flow Control
Cameron International – Measurement Division
Cameron International – Petreco Process Systems
Cameron International – Process Valves Division
Cameron International – Reciprocating
Cameron International – Subsea Systems
Cameron International – Surface Systems
Cameron International – Valves & Measurement
CenterPoint Energy
Chesapeake Energy Corporation
Chesapeake Energy Corporation – CEMI
Chesapeake Energy Corporation – Chesapeake Midstream Partners
Chesapeake Energy Corporation – Compass
Chesapeake Energy Corporation – Diamond Y
Chesapeake Energy Corporation – Great Plains
Chesapeake Energy Corporation – Hodges
Chesapeake Energy Corporation – Midcon
Chesapeake Energy Corporation – Nomac
Cimarex Energy Co.
Cinco Natural Resources Corporation
Citation Oil & Gas Corp.
Cleco Corporation
Colonial Pipeline Company
Constellation Energy Partners LLC
Copano Energy
Crosstex Energy Services
DCP Midstream, LLC
DPL Inc.
DTE Energy
Davis Petroleum Corp.
Det Norske Veritas USA
Devon Energy
Dominion Resources, Inc.
Dominion Resources, Inc. – Dominion Energy
Dominion Resources, Inc. – Dominion Generation
Dominion Resources, Inc. – Dominion Virginia Power
Dresser-Rand Group Inc.
Dresser-Rand Group Inc. – Dresser-Rand New Equipment
Dresser-Rand Group, Inc. – Dresser-Rand Product Services
Dresser-Rand Group, Inc. –NAO
DynMcDermott Petroleum Operations Company
ENSCO International, Inc.
ENSCO International, Inc. – Deepwater Business Unit
ENSCO International, Inc. – North & South America Business Unit
EOG Resources, Inc.
EXCO Resources, Inc.
EXCO Resources, Inc. – EXCO Appalachia
EXCO Resources, Inc. – EXCO East TX/LA
EXCO Resources, Inc. – EXCO Midstream
EXCO Resources, Inc. – EXCO Permian/Rockies
Edison Mission Energy
Edison Mission Energy – EME Homer City Generation
Edison Mission Energy – Edison Mission O&M
Edison Mission Energy – Energy Mission Marketing & Trading
Edison Mission Energy – Midwest Generation EME
Edison Mission Energy – Midwest Generation, LLC
El Paso Corporation
El Paso Corporation – Exploration & Production
El Paso Corporation – Pipeline Group
EnerVest, Ltd.
Energen Corporation
Energen Corporation – Energen Resources Corporation
Energy Future Holdings Corporation
Energy Future Holdings Corporation – Luminant
Energy Future Holdings Corporation – TXU Energy
Enerplus Resources Fund – Enerplus Resources (USA) Corporation
Eni US Operating Company, Inc.
Entegra Power Services, LLC
Equal Energy Ltd. – Altex Energy Corporation
Explorer Pipeline Company
Exterran
Fasken Oil and Ranch, Ltd.
Forest Oil Corporation
GE Oil & Gas Operations LLC – PII North America, Inc.
Genesis Energy, LLC
Global Industries
Great River Energy
Halliburton Company
Helmerich & Payne, Inc.
Hercules Offshore, Inc.
Hess Corporation – Exploration & Production
HighMount Exploration & Production LLC
Hilcorp Energy Company
Hilcorp Energy Company – Harvest Pipeline Company
Holly Corporation
Holly Corporation – Asphalt Company
Holly Corporation – Logistic Services
Holly Corporation – Navajo Refining Company
Holly Corporation – Refining and Marketing Woods Cross
Holly Refining and Marketing Tulsa LLC
Hunt Consolidated – Hunt Oil Company
Husky Energy Inc.
ION Geophysical Corporation
J-W Operating Company
J-W Operating Company – Cohort Energy Company
J-W Operating Company – J-W Gathering Company
J-W Operating Company – J-W Measurement Company
J-W Operating Company – J-W Power Company
J-W Operating Company – J-W Wireline & Excell
Kinder Morgan, Inc.
Lario Oil & Gas Company
Legacy Reserves, LP
Linn Energy, LLC
M-I SWACO
MCX Exploration (USA), Ltd.
MDU Resources Group, Inc.
MDU Resources Group, Inc. – WBI Holdings, Inc.
Magellan Midstream Holdings, LP
Magellan Midstream Holdings, LP – Pipeline/Terminal Division
Magellan Midstream Holdings, LP – Transportation
MarkWest Energy Partners LP
MarkWest Energy Partners LP – Gulf Coast Business Unit
MarkWest Energy Partners LP – Liberty Business Unit
MarkWest Energy Partners LP – Northeast Business Unit
MarkWest Energy Partners LP – Southwest Business Unit
Medco Petroleum Management
Mestena Operating, Ltd.
Mirant Corporation
Mitsui E&P USA LLC
Modec International Inc.
Murphy Oil Corporation
New York Power Authority
New York Power Authority – Blenheim-Gilboa Power Project
New York Power Authority – Clark Energy Center
New York Power Authority – Niagara Power Project
New York Power Authority – Richard M. Flynn Power Plant
New York Power Authority – St. Lawrence/FDR Power Project
Newfield Exploration Company
Nexen Petroleum USA, Inc.
NiSource Inc.
NiSource Inc. – Bay State Gas Company
NiSource Inc. – Columbia Gas of Kentucky
NiSource Inc. – Columbia Gas of Ohio
NiSource Inc. – Columbia Gas of Pennsylvania
NiSource Inc. – Columbia Gas of Virginia
NiSource Inc. – NiSource Energy Technologies
NiSource Inc. – NiSource Gas Transmission & Storage
NiSource Inc. – Northern Indiana Fuel & Light
NiSource Inc. – Northern Indiana Public Service Company
NiSource Inc. – Transmission Corporation
Nippon Oil Exploration USA Ltd.
Noble Corporation
Noble Corporation – Noble Drilling Services, Inc.
Noble Energy, Inc.
OGE Energy Corporation
ONEOK, Inc.
ONEOK, Inc. – Kansas Gas Service Division
ONEOK, Inc. – ONEOK Energy Services Company
ONEOK, Inc. – ONEOK Partners

PROXY

ONEOK, Inc. – Oklahoma Natural Gas Division
ONEOK, Inc. – Texas Gas Services Division
Occidental Petroleum Corporation – Thums Long Beach Company
Oceaneering International, Inc.
Oceaneering International, Inc. – Americas
Oceaneering International, Inc. – Inspection
Oceaneering International, Inc. – Multiflex
Oceaneering International, Inc. – OIE
PD Holdings Company
PJM Interconnection
PSNC Energy
Parallel Petroleum LLC
Parker Drilling Company
Pason Systems USA Corp.
Pepco Holdings, Inc.
Petroleum Development Corporation
Pioneer Drilling Company
Pioneer Natural Resources USA, Inc.
Plains Exploration & Production Company
Pride International
Puget Sound Energy
Questar Corporation
Questar Corporation – QEP Resources
Quicksilver Resources Inc.
R. Lacy, Inc. – R. Lacy Services, Ltd.
RAM Energy Resources, Inc.
RKI Exploration & Production, LLC
Range Resources Corp.
Regency Energy Partners LP
Repsol Services Company
Resolute Natural Resources Company, LLC
Rosewood Resources, Inc.
Rosewood Resources, Inc. – Advanced Drilling Technologies
Rowan Companies, Inc.
SCANA Corporation
SCANA Corporation – Carolina Gas Transmission Corporation
SCANA Corporation – SC Electric & Gas
SandRidge Energy, Inc.
Schlumberger Limited
Science Applications International Corporation (SAIC)
Seawell Americas, Inc.
SemGroup Corporation
SemGroup Corporation – SemCrude
SemGroup Corporation – SemGas
SemGroup Corporation – SemStream
Seneca Resources Corporation
Seneca Resources Corporation – Bakersfield
Seneca Resources Corporation – Williamsville
Smith International
SourceGas LLC
Southern Company
Southern Company – Alabama Power Company
Southern Company – Georgia Power
Southern Company – Gulf Power Company
Southern Company – Mississippi Power Company
Southern Union Company
Southern Union Company – Missouri Gas Energy
Southern Union Company – New England Gas
Southern Union Company – Panhandle Energy
Southern Union Company – Southern Union Gas Services
Southwestern Energy Company
Sprague Energy Corp.
Stantec Inc.
Superior Energy Services, Inc. LLC
Superior Natural Gas Corporation
TAQA New World Inc.
TAQA North USA
TGS-NOPEC Geophysical Company
Talisman Energy Inc. US
Tecpetrol Corporation
Tellus Operating Group, LLC
Tesco Corporation
The Williams Companies, Inc.
ThermaSource, Inc.
ThermaSource, Inc. – ThermsSource Cementing
TransCanada Corporation
TransCanada Corporation – US Pipeline Central
Transocean, Inc.
Unit Corporation
Unit Corporation – Superior Pipeline Company, LLC
Unit Corporation – Unit Drilling Company
Unit Corporation – Unit Petroleum Company
Venoco, Inc.
Verado Energy, Inc.
WGL Holdings, Inc. – Washington Gas
XTO Energy, Inc.
Xcel Energy Inc.

Towers Watson 2010/2011 Top Management Compensation Survey

3M Company
84 Lumber Company
A. O. Smith Corporation
AAA
AAR Corporation
Aaron’s, Inc.
Abbott Laboratories
Abercrombie & Fitch
ABM Industries, Inc.
Accident Fund Insurance Company of America
Accor North America
Acme Industries
The Actors Fund of America
Acuity
Acuity Brands, Inc.
ACUMED LLC
Administaff, Inc.
Adobe Systems, Inc.
ADTRAN Incorporated
Advance Auto Parts, Inc.
Advanced Micro Devices
AECOM Technology Corporation
Aegon USA
Aeronix, Inc.
Aeropostale, Inc.
AES Corporation
Aetna, Inc.
Affinia Group Intermediate Holdings, Inc.
AFLAC Incorporated
AFP, Inc.
AGCO Corporation
Agilent Technologies, Inc.
Agilysys, Inc.
AGL Resources, Inc.
AgriBank, FCB
Air Products & Chemicals, Inc.
AirTran Holdings, Inc.
Aker Solutions
AKSteel Holding Corporation
Alaska Air Group, Inc.
Albemarle Corporation
Alcoa, Inc.
Alfa Laval, Inc.
Allegheny County Sanitary Authority
Allegheny Energy, Inc.
Allegheny Technologies, Inc.
Allegiance Health
Allergan, Inc.
Allete, Inc.
Alliance Data Systems Corporation
Alliance Defense Fund
Alliance Residential LLC
Alliant Energy Corporation
Allstate Corporation
Ally Financial, Inc.
Alpha Natural Resources, Inc.
ALSAC St. Jude
Amazon.com, Inc.
Ambac Financial Group
Ambius
Ameren Corporation
American Cancer Society, Inc.
American Commercial Lines, Inc.
American Dehydrated Foods, Inc.
American Eagle Outfitters, Inc.
American Electric Power Company
American Express Company
American Family Insurance
American Greetings Corporation
American International Group, Inc.
American National Insurance
American Tire Distributors Holdings, Inc.
American Tower Corporation
American University
American Water
AMERIGROUP Corporation
AmeriPride Services, Inc.
Ameriprise Financial, Inc.
AmerisourceBergen Corporation
Ameristar Casinos
Ames True Temper
AMETEK, Inc.
AMETEK, Inc./Advanced Measurement Technologies
Amgen, Inc.
Amica Mutual Insurance Company
Amkor Technology, Inc.
Amphenol Corporation
AMR Corporation
Anadarko Petroleum Corporation
Analog Devices
Anchor Bank NA
Andersen Corporation
Andersons, Inc.
Anixter International, Inc.
Annaly Capital Management
AnnTaylor Stores Corporation
AOC LLC
Aon Corporation
Apache Corporation
Apollo Group
Apple, Inc.
Applied Materials, Inc.
AptarGroup, Inc.
ARAMARK Corporation
Arch Coal, Inc.
Archstone
Armed Forces Insurance
Armstrong World Industries
Arrow Electronics, Inc.
ArvinMeritor, Inc.
Asahi Kasei Plastics NA, Inc.
Asbury Automotive Group, Inc.
Ascent Media Group

ASCO – Valve
Ash Grove Cement Company
Ashland, Inc.
Asset Marketing Service, Inc.
Assurant, Inc.
Asurion Corporation
AT&T, Inc.
Atlas Energy, Inc.
Atmos Energy Corporation
Aurora Healthcare
The Auto Club Group
Autodesk, Inc.
Autoliv, Inc.
Automobile Club of Southern California
AutoNation, Inc.
AutoZone, Inc.
Avery Dennison Corporation
Avis Budget Group
Avista Corporation
Avon Products, Inc.
Axsys
B Braun Medical, Inc.
B/E Aerospace, Inc.
Babson College
Baker Hughes, Inc.
Baldor Electric Company
Ball Corporation
Bank of America Corporation
Bank of New York Mellon Corporation
Baptist Health
Barilla America, Inc.
Barloworld Handling
Basler Electric Company
Baxter International, Inc.
Baylor College of Medicine
Baylor Health Care System
BB&T Corporation
Beacon Roofing Supply, Inc.
Bechtel Systems & Infrastructure, Inc.
Beckman Coulter, Inc.
Becton Dickinson & Company
Belk, Inc.
Bemis Company, Inc.
Bemis Manufacturing Company
Benchmark Electronics, Inc.
The Bergquist Company
Berkshire Hathaway
Berry Plastics Corporation
Berwick Offray LLC
Best Buy Company, Inc.
Big Lots, Inc.
Bimbo Bakeries USA
Biodynamic Research Corporation
Biogen Idec, Inc.
Biomet
Bio-Rad Laboratories, Inc.
BJ Services Company
BJ's Wholesale Club, Inc.
Black Hills Corporation
Blackrock, Inc.
Blackstone Group LP
Blockbuster, Inc.
Blue Cross Northeastern Pennsylvania
Blue Cross of Idaho Health Service, Inc.
BlueCross BlueShield of Arizona
BlueCross BlueShield of Delaware
BlueCross BlueShield of Louisiana
BlueCross BlueShield of Nebraska
BlueCross BlueShield of South Carolina
BlueCross BlueShield of Tennessee
Bluelinx Holdings, Inc.
BMW Manufacturing Corporation
Board of Governors of the
Federal Reserve System
The Body Shop
Boeing Company
Boise Cascade Holdings LLC
Boise, Inc.
Bon-Ton Stores, Inc.
Borders Group, Inc.
Borg Warner
Bosch Packaging Services
Bosch Rexroth Corporation
Boston Scientific Corporation
Boy Scouts of America
Boyd Gaming Corporate
Bradley Corporation
Brady Corporation
Bridgepoint Education
Briggs & Stratton Corporation
Brightpoint, Inc.
Brinks Company
Bristol-Myers Squibb Company
Broadcom Corporation
Broadlane, Inc.
Broadridge Financial Solutions
Brocade Communications Systems
Brookdale Senior Living
Brown Shoe Company, Inc.
Brownells, Inc.
Brown-Forman Corporation
Brunswick Corporation
Bryant University
BSSI
Bucyrus International, Inc.
Buffets, Inc.
Burger King Holdings, Inc.
C H Robinson Worldwide, Inc.
C.R. Bard, Inc.
Cabelas, Inc.
Cablevision Systems Corporation
Cabot Corporation
Caci International, Inc.
Caelum Research Corporation
California Casualty Management Company
California Dental Association
Calpine Corporation
Calumet Specialty Products Partners LP
Cameron International Corporation
Campbell Soup Company
Career Education Corporation
Carhartt, Inc.
CaridianBCT, Inc.
Carlisle Cos, Inc.
Carlson Companies, Inc.
CarMax
Carpenter Technology Corporation
Carter
Carter's, Inc.
Catalyst Health Solutions
Caterpillar, Inc.
CB Richard Ellis
CBS Corporation
CC Media Holdings, Inc.
CDM
CEC Entertainment, Inc.
CEI
Celanese Corporation
Celgard, Inc.
Celgene Corporation
CEMEX, Inc.
Centene Corporation
Comcast Corporation
Comerica, Inc.
Commercial Metals
CommScope, Inc.
Community Coffee Company LLC
Community Health Systems, Inc.
The Community Preservation Corporation
Computer Task Group
ConnectiCare Capital LLC
Conocophillips
Consol Energy, Inc.
Consolidated Edison, Inc.
Constellation Energy
Continental Airlines, Inc.
Continental Data Graphics
Convergys Corporation
Con-Way
Cook Communications Ministries
Cooper Tire & Rubber Company
Cooper-Standard Holdings, Inc.
CooperVision, Inc.
Core Mark Holding Company, Inc.
Corinthian Colleges
Corn Products International, Inc.
Cornell University
Corning, Inc.
Correctional Medical Services
Corrections Corporation of America
Costco Wholesale Corporation
Country Insurance & Financial
Country of Spotsylvania
Covance, Inc.
Covanta Holding Corporation
Coventry Health Care, Inc.
CPS Energy
Cracker Barrel Old Country Store, Inc.
Crane Company
Crosstex Energy, Inc.
Crown Castle International Corporation
CSX Corporation
CTS Corporation
Cultural Institute Retirement System
Cummins, Inc.
CUNA Mutual Group
Curtiss Wright Corporation
CVREnergy, Inc.
CVS Caremark
Cytec Industries, Inc.
D R Horton, Inc.
Daimler Financial Services
Dallas County
Dal-Tile, Inc.
Dana Holding Corporation
Danaher Corporation
Data Center, Inc.
DaVita, Inc.
Dean Foods Company
The Decurion Corporation
Deere & Company
Dekalb Regional Healthcare Systems
Delta Air Lines, Inc.
Delta Dental Plan of Michigan
Deluxe Corporation
Denny's, Inc.
Denso International America
DENTSPLY International, Inc.
DePaul University
Devon Energy Corporation
Dex One Corporation
DFW International Airport
Dick's Sporting Goods, Inc.
Dickstein Shapiro LLP
Diebold, Inc.
Dillards, Inc.
DIRECTV
Discover Financial Services, Inc.
Discovery Communications, Inc.
DISH Network
Diversey, Inc.
Doherty Employer Services
Dole Food Company, Inc.
Dollar General Corporation
Dollar Thrifty Automotive Group

Dominion Resources, Inc.
Donaldson Company, Inc.
Dover Corporation
Dow Chemical
DPL, Inc.
Dr. Pepper Snapple Group, Inc.
Dresser-Rand Group, Inc.
DST Systems, Inc.
DTE Energy
Duane Reade Holdings, Inc.
Duke Energy Corporation
Duke Realty Corporation
Duke University & Health System
Dun & Bradstreet Corporation
DuPont
Dupont Fabros Technology
Dyn McDermott
Dynegy, Inc.
E TRADE Financial Corporation
Early Warning Services
Eastman Chemical Company
Eastman Kodak Company
Eaton Corporation
eBay, Inc.
Echostar Corporation
Ecolab, Inc.
Edison Mission Energy
Edward Jones & Company
Edwards Lifesciences
Einstein Noah Restaurant Group
El Paso Corporation
Electrolux Homecare of North America
Eli Lilly & Company
Elizabeth Arden, Inc.
EMC Corporation
EMCOR Group, Inc.
Emerson Climate Technologies, Inc.
Emerson Electric
Enbridge Energy Partners LP
Energizer Holdings, Inc.
Energy Enterprise Solutions LLC
Energy Future Holdings
Energy Transfer Equity LP
EnergySolutions, Inc.
Enpro Industries (Fairbanks Morse Engine)
Entergy Corporation
Enterprise GP Holdings LP
EOG Resources, Inc.
EON US LLC
Equifax, Inc.
Equity Residential
Erickson Retirement Communities
Erie Insurance Group
ESCO Corporation
ESCO Technologies
Esterline Technologies Corporation
Etnyre International, Ltd.
Evraz, Inc.
Exel, Inc.
Exelon Corporation
Exempla Health Care, Inc.
Exide Technologies
Expedia, Inc.
Express Scripts, Inc.
Exterran Holdings, Inc.
Extra Space Storage
Exxon Mobil Corporation
FAIR Plan Insurance Placement Facility of Pennsylvania
Fairfield Manufacturing
Family Dollar Stores
Fannie Mae
Farmland Foods, Inc.
Fastenal Company
Federal Reserve Bank of Boston
Federal Reserve Bank of Chicago
Federal Reserve Bank of Cleveland
Federal Reserve Bank of Dallas
Federal Reserve Bank of Kansas City
Federal Reserve Bank of Minneapolis
Federal Reserve Bank of Philadelphia
Federal Reserve Bank of San Francisco
Federal Reserve Bank of St. Louis
FedEx Express
FedEx Ground
FedEx Office
Fender Musical Instruments
Ferguson Enterprises
Fermi National Accelerator Laboratory
FerrellGas, Inc.
Ferro Corporation
Fiberweb
Fidelity National Financial
Fidelity National Information Services
Fifth Third Bancorp
The First American Corporation
First Bank
First Citizens Bank
First Horizon National Corporation
First Solar, Inc.
FirstEnergy Corporation
Fiserv, Inc.
Fleetwood Group
Flexcon Company, Inc.
Flexible Steel Lacing Company
Florida Power & Light Company
Flowers Foods, Inc.
Flowserve Corporation
Fluor Corporation
FMC Corporation
FMC Technologies, Inc.
Follett Corporation
Foot Locker, Inc.
Ford Motor Company
Fortune Brands
Fossil, Inc.
Foster Poultry Farms
Foundation for California Community Colleges
Franklin Resources, Inc.
Franklin W. Olin College of Engineering
Freeman Dallas Corporate Office
Freeport-McMoRan Copper & Gold, Inc.
Fremont Group
Friendly Ice Cream Corporation
Froedtert & Community Health
Frontier Communications Corporation
Frontier Oil Corporation
Funeral Directors Life Insurance Company
G&K Services
Gallagher Arthur J & Company
Gannett Company
Gap, Inc.
Gardner Denver, Inc.
Gas Technology Institute
Gaylord Entertainment
General Cable Corporation
General Dynamics Corporation
General Dynamics Information Technology
General Electric Company
General Nutrition, Inc.
Genesis Energy
Gentiva Health Services
Genuine Parts Company
Genworth Financial, Inc.
Genzyme Corporation
Georg Fischer Signet LLC
Georgia Gulf Corporation
Georgia Institute of Technology
Gerdau Ameristeel
Gilbarco, Inc.
Gilead Sciences, Inc.
Glatfelter Company
The Gleason Works
Global Partners LP
GOJO Industries, Inc.
Gold Eagle Company
Goldman Sachs Group, Inc.
Goodman Manufacturing
Goodrich Corporation
Goodyear Tire & Rubber Company
Google, Inc.
Graco, Inc.
Graham Packaging Company, Inc.
Grande Cheese Company
Grange Mutual Insurance Company
Granite Construction, Inc.
Graphic Packaging Holding Company
Graybar Electric Company, Inc.
Great American Insurance/Great American Financial
Great Plains Energy, Inc.
Greenheck Fan Corporation
Greif, Inc.
Greyhound Lines, Inc.
Grinnell Mutual Reinsurance Company
Group 1 Automotive, Inc.
Grow Financial Federal Credit Union
Growmark, Inc.
GTECH Corporation
GuideStone Financial Resources
Habitat for Humanity International
Halliburton Company
Hancock Holdings Company
Hanesbrands, Inc.
Hannaford Bros. Company
Hanover Insurance Group, Inc.
Hapag-Lloyd (America), Inc.
Harley Davidson Motor Company
Harman International Industries
Harrahs Entertainment, Inc.
Harris County Hospital District
Harsco Corporation
Hartford Financial Services
Harvard Vanguard Medical Associates
Harvey Industries
Hasbro, Inc.
Hastings Mutual Insurance Company
Hawaiian Electric Industries, Inc.
Haynes & Boone LLP
Hayward Industries, Inc.
Hazelden Foundation
HCA, Inc.
HCC Insurance Holdings, Inc.
HD Supply, Inc.
HDR, Inc.
Health Care Service Corporation
Health Management Association
Health Net
Health Partners
Health Plus of Michigan
HealthNow New York
HealthSouth Corporation
HealthSpring, Inc.
Heartland Food Corporation
Heartland Payment Systems, Inc.
Heat Transfer Research, Inc.
Helmerich & Payne, Inc.
Hendrick Medical Center
Hendrickson International
Henry Ford Health System
Hercules Offshore
Herman Miller, Inc.
Hershey Company
Hertz Global Holdings, Inc.

Hess Corporation
Hewitt Associates, Inc.
Hewlett-Packard Company
Hexion Specialty Chemicals, Inc.
High Industries, Inc.
Highmark, Inc.
Hill Phoenix
Hilti, Inc.
Hitachi America, Ltd.
HNI Corporation
HNTB Corporation
Holden Industries, Inc.
Holly Corporation
Hologic, Inc.
Home Depot, Inc.
Home Shopping Network
Honeywell International, Inc.
Horizon Blue Cross Blue Shield
Hormel Foods Corporation
Hospira, Inc.
Host Hotels & Resorts, Inc.
Hostess Brands
Hot Topic, Inc.
Hubbell, Inc.
Hudson City Bancorp, Inc.
Hu-Friedy Manufacturing Company, Inc.
Humana, Inc.
Hunter Industries
Huntington Bancshares
Huntsman Corporation
Huron Consulting Group
Hutchinson Technology Incorporated
Hyatt Hotels Corporation
Hyundai Motor Manufacturing of Alabama
IAC/Interactivecorp
Icahn Enterprises LP
IDEX Corporation
IDEXX Laboratories, Inc.
IDT Corporation
IKON Office Solutions
Illinois Tool Works, Inc.
Imation Corporation
IMS Health, Inc.
Indiana Farm Bureau Insurance
Inergy Holdings LP
Information Management Service
Ingersoll Rand
Ingles Markets, Inc.
Ingram Industries, Inc.
Ingram Micro, Inc.
Insight Enterprises, Inc.
In-Sink-Erator
Institute for Defense Analyses
Institute of Nuclear Power Operations
Insurance Auto Auctions
Integrys Energy Group, Inc.
Intel Corporation
Interbake Foods, Inc.
InterMetro Industries Corporation
International Assets Holding Company
International Business Machines Corporation
International Dairy Queen, Inc.
International Flavors & Fragrances
International Game Technology
International Paper Company
Interpublic Group of Companies
Intertape Polymer Group
Intuit, Inc.
Invacare Corporation
Invensys Controls
Iron Mountain Canada Corporation
The Irvine Company
Ithaca College
Itochu International, Inc.
Itron, Inc.
ITT Corporation
ITT Industries – AES
J J Keller & Associates, Inc.
J R Simplot Company
J&J Worldwide Services
J.C. Penney Company
Jabil Circuit, Inc.
Jack In The Box, Inc.
Jacobs Engineering Group, Inc.
Jacobs Technology, Inc.
James Hardie Building Products
Jarden Corporation
JB Hunt Transport Services, Inc.
Jet Blue Airways
JM Family Enterprises
Jo-Ann Stores, Inc.
John Crane, Inc.
John Wiley & Sons, Inc.
Johns Hopkins University
Johnson & Johnson
Johnson Controls, Inc.
Johnson Financial Group
Jones Apparel Group, Inc.
Jones Financial Companies LLLP
Jones Lang LaSalle
Jostens, Inc.
Joy Global, Inc.
JPMorgan Chase & Company
Judicial Council of California
Juniper Networks, Inc.
K Hovnanian Companies LLC
Kalsec, Inc.
Kansas Farm Bureau
KAR Auction Services, Inc.
Katun Corporation
KB Home
KBR, Inc.
Keihin North America
Kellogg Company
Kelly Services, Inc.
Kettering University
Kewaunee Scientific Corporation
Keycorp
Keystone Automotive Industries
Keystone Foods Corporation
KI, Inc.
Kimberly-Clark Corporation
Kimley-Horn and Associates, Inc.
Kinder Morgan Energy
Kindred Healthcare
Kinetic Concepts, Inc.
King Pharmaceuticals, Inc.
Kingston Technology
Klein Tools
Kohler Company
Kohls Corporation
Komatsu America Corporation
Kraft Foods, Inc.
L. L. Bean, Inc.
L-3 Communications Holdings, Inc.
L-3 Communications, Global Security & Engineering Solutions
La Macchia Enterprises
Lab Volt Systems
Laboratory Corporation of America Holdings
Laclede Group, Inc.
Lake Federal Bank
Lake Forest Academy
Lake Region Medical
Lance, Inc.
Landstar System, Inc.
Lantech.com
Las Vegas Sands Corporation
Leap Wireless International, Inc.
Lear Corporation
Legal & General America
Leggett & Platt, Inc.
Lender Processing Services
Lennar Corporation
Lennox International, Inc.
Level 3 Communications, Inc.
Levi Strauss & Company
Lexmark International, Inc.
Liberty Global, Inc.
Liberty Media Corporation
Lieberman Research Worldwide
Life Technologies Corporation
Lifepoint Hospitals, Inc.
Limited Brands
Lincare Holdings, Inc.
Lincoln Electric Holdings, Inc.
Lincoln National Corporation
Lithia Motors, Inc.
Littelfuse, Inc.
Little Lady Foods
Live Nation Entertainment, Inc.
Liz Claiborne
LKQ Corporation
Lockheed Martin Corporation
Loews Corporation
Lorillard, Inc.
Los Angeles Unified School District
Louisiana Pacific
Lowe's Companies, Inc.
Lower Colorado River Authority
Lozier Corporation
LPL Investment Holdings, Inc.
LSG Sky Chefs
LSI Corporation
Lubrizol Corporation
Lufthansa AirPlus Servicekarten GmbH
Luther Midelfort-Mayo Health System
Lutron Electronics
Luxottica Retail
M & F Worldwide Corporation
M & T Bank Corporation
Macy's, Inc.
Magellan Health Services
Magna Seating Systems Engineering
Malco Products, Inc.
Malt-O-Meal
Manitowoc Company
MANN+HUMMEL USA, Inc.
Manpower International, Inc.
Manpower, Inc.
ManTech International
MAPFRE USA, Corporation
Marathon Oil Corporation
Maricopa County Office of Management & Budget
Maricopa Integrated Health System
Maritz, Inc.
Markel Corporation
Market Planning Solutions, Inc.
Marriott International, Inc.
Mars North America
Marsh & McLennan Companies
Marshall & Ilsley Corporation
Marshfield Clinic
MARTA
Martin Marietta Materials, Inc.
Mary Kay, Inc.
Maryland Department of Transportation
Masco Corporation
Massey Energy Company
MasTec, Inc.
Master Halco
Mattel, Inc.
Maxim Integrated Products, Inc.
Mayo Clinic

McAfee, Inc.
McCormick & Company, Inc.
McDonald's Corporation
MCG Health, Inc.
McGraw-Hill Companies
McKesson Medical-Surgical
MDU Resources Group, Inc. (WBI Holdings)
MeadWestvaco Corporation
Mecklenburg County
Medco Health Solutions, Inc.
Media General, Inc.
Medline Industries
Men's Wearhouse, Inc.
Mercer University
Merck & Company
Mercury General Corporation
Merit Medical Systems
MeritCare Health System
Merrill Corporation
The Methodist Hospital
MetroPCS Communications, Inc.
Metropolitan Life Insurance Company
Metropolitan Transit Authority
Mettler-Toledo International, Inc.
MFS Investment Management
MGIC Investment Corporation
MGM Mirage
Miami Children's Hospital
Miami Dade Community College
Michael Baker Corporation
Michael Foods, Inc.
Michaels Stores, Inc.
Micron Technology, Inc.
Midwest Research Institute
Mike Albert Leasing, Inc.
Millennium Inorganic Chemicals
Mine Safety Appliances Company
Minnesota Management & Budget
Mirant Corporation
Mission Foods
Missouri Department of Conservation
Missouri Department of Transportation
Mitsubishi International Corporation
Mitsubishi Motor Manufacturing
MMS Consultants, Inc.
Mohawk Industries
Mohegan Sun Casino
Molex, Inc.
Molina Health Care, Inc.
Molson Coors Brewing Company
Momentive Performance Materials, Inc.
Monsanto Company
Moody's Corporation
Moog, Inc.
Morgan Stanley
Motorola, Inc.
MTA Long Island Bus
MTD Products, Inc.
MTS System Corporation
Mueller Industries, Inc.
Murphy Oil Corporation
Mutual of Enumclaw Insurance Company
Mutual of Omaha
Mylan, Inc.
NACCO Industries, Inc.
Nalco Holding Company
NASDAQ OMX Group, Inc.
Nash Finch Company
National Academies
National Fuel Gas Company
National Futures Association
National Interstate Insurance Company
National Oilwell Varco, Inc.
National Safety Council
National Tobacco Company
Nature's Sunshine Products, Inc.
Navistar International Corporation
Navy Exchange Service Command
NBTY, Inc.
NCCI Holdings, Inc.
NCR Corporation
Nebraska Public Power District
Neiman Marcus
Netflix, Inc.
New Jersey Resources Corporation
New York Times Company
Newell Rubbermaid, Inc.
Newmont Mining Corporation
NewPage Corporation
Nicor Gas
Nicor, Inc.
The Nielsen Company
NII Holdings, Inc.
NiSource Corporate Services
Nissin Foods (USA) Company, Inc.
NJM Insurance Group
Noble Energy, Inc.
The Nordam Group
Nordson Corporation
Nordstrom
Nordstrom, Inc.
Norfolk Southern Corporation
North Carolina State Employees' Credit Union
North Texas Tollway Authority
Northeast Utilities
Northern Trust Corporation
Northrop Grumman Corporation
Northwestern Mutual
NovaMed Corporation
NRG Energy, Inc.
NRUCFC
Nstar
Nucor Corporation
NuStar Energy LP
NV Energy, Inc.
NVIDIA Corporation
NVR, Inc.
NYSE Euronext
O'Reilly Automotive, Inc.
Occidental Petroleum Corporation
Oceaneering International
Oerlikon Balzers Coating USA, Inc.
Office Depot, Inc.
OfficeMax
OGE Energy Corporation
Ohio Public Employees Retirement System
Ohio State University
The Ohio State University Medical Center
Ohio University
OHL
Oil States International, Inc.
Oil-Dri Corporation of America
Old Dominion Electric Cooperative
Old Republic Companies
Omnicare, Inc.
Omnicom Group
Omnova Solutions, Inc.
ON Semiconductor Corporation
ONEOK, Inc.
The Oppenheimer Group
Orange County Government
Orbital Science Corporation
Oregon State Lottery
Oshkosh Corporation
Owens & Minor, Inc.
Owens Corning
Owens-Illinois, Inc.
Oxford Industries
PACCAR, Inc.
Pacer International, Inc.
Packaging Corporation of America
Pactiv Corporation
Pall Corporation
The Pampered Chef
Panduit Corporation
Pantry, Inc.
Papa John's International
Parsons Child & Family Center
Patterson Companies, Inc.
PC Connection, Inc.
Peabody Energy Corporation
Pearson Education
Penn National Gaming, Inc.
Penn State Hershey Medical Center
Penske Automotive Group, Inc.
Pentair, Inc.
Pep Boys–Manny Moe & Jack
Pepco Holdings, Inc.
Pepsi Bottling Group, Inc.
PepsiCo, Inc.
Perkinelmer, Inc.
Petsmart, Inc.
Pfizer, Inc.
PG&E Corporation
Pharmavite LLC
Pharmerica Corporation
PHH Arval
PHH Corporation
PHI, Inc.
Philip Morris International, Inc.
Phillips – Van Heusen Corporation
Phoenix Companies, Inc.
Picerne Military Housing
Piedmont Natural Gas Company, Inc.
Pier 1 Imports
Pilgrim's Pride Corporation
Pinnacle Airlines
Pinnacle Foods Finance LLC
Pinnacle West Capital Corporation
Pinnacol Assurance
Pioneer Natural Resources Company
Pitney Bowes, Inc.
Plains All American Pipeline LP
Plexus Corporation
PM Company
PNC Financial Services Group, Inc.
PNM Resources, Inc.
Polaris Industries, Inc.
Polymer Technologies
Polyone Corporation
Popular, Inc.
Port Authority of Allegheny County
Port of Portland
Portland General Electric Company
Poudre Valley Health Systems
PPG Industries, Inc.
PPL Corporation
Praxair, Inc.
Preformed Line Products Company
Premera Blue Cross
Priceline.com, Inc.
Pride International, Inc.
Prince William Health System
Principal Financial Group, Inc.
Probuild Holdings, Inc.
Progress Energy, Inc.
Progressive Corporation
Project Management Institute
Property Casualty Insurers Association of America
Protective Life Corporation
Prudential Financial, Inc.
Psion Teklogix, Inc.
Psychiatric Solutions, Inc.
Public Service Enterprise Group, Inc.

Public Storage
Public Utility District #1 of Chelan County
Publix Super Markets, Inc.
Puget Energy, Inc.
Pultegroup, Inc.
QSC Audio Products, Inc.
QTI Human Resources
Qualcomm, Inc.
Quality Bicycle Products
Quanta Services, Inc.
Quest Diagnostics Incorporated
Questar Corporation
Quiksilver, Inc.
Qwest Communications International, Inc.
R L I Insurance Company
R L Polk & Company
Radio One
Radioshack Corporation
Ralcorp Holdings, Inc.
The Raymond Corporation
Raymond James Financial
Raytheon Company
REA Magnet Wire Company, Inc.
Realogy Corporation
Recology
Red Wing Shoe Company
Redcats USA
Regal Entertainment Group
Regal-Beloit
The Regence Group
Regency Centers Corporation
Regions Financial Corporation
Reinsurance Group of America
Reliance Steel & Aluminum Company
Remington Arms Company, Inc.
Renaissance Learning, Inc.
Renown Health
Rent-A-Center, Inc.
Republic Services, Inc.
Res-Care, Inc.
Rexel, Inc.
Reynolds American, Inc.
Rice University
RiceTec, Inc.
Rich Products Corporation
Richco
Ricoh Electronics, Inc.
Rite – Hite Holding Corporation
Robert Bosch LLC
Robert Bosch Tool Corporation
Robert Half International, Inc.
Roche Diagnostics
Rock-Tenn Company
Rockwell Automation
Rockwell Collins, Inc.
Rockwood Holdings, Inc.
Rollins, Inc.
Roper Industries
Roper Industries, Inc.
Ross Stores, Inc.
Rowan Companies, Inc.
Royal Bank of Canada
Royal Caribbean Cruise Line
RR Donnelley & Sons Company
RRI Energy
RSC Equipment Rental
RSM McGladrey
Ruddick Corporation
Ryder System, Inc.
The Ryland Group
S&C Electric Company
Safety-Kleen Systems, Inc.
Safeway, Inc.
Safilo USA
SAGE Publications
SAIC, Inc.
Saks, Inc.
Sakura Finetek USA, Inc.
Salk Institute
Sally Beauty Holdings, Inc.
Salt River Project
Samuel Roberts Noble Foundation
San Antonio Water System
San Manuel Band of Mission Indians
Sanderson Farms, Inc.
Sandisk Corporation
Sanmina-Sci Corporation
SAS Institute, Inc.
Sauer-Danfoss, Inc.
Savannah River Nuclear Solutions LLC
Save Mart
SCANA Corporation
Scansource, Inc.
SCF Arizona
Schaumburg Township District Library
Schein Henry, Inc.
Schneider Electric
Schneider National, Inc.
Schnitzer Steel Industries
Schwan Food Company
Scientific Research Corporation
The Scooter Store
Scott & White Hospital
Scotts Miracle-Gro Company
Scripps Networks Interactive, Inc.
Seaboard Corporation
Seacoast National Bank
Seacor Holdings, Inc.
Sealed Air Corporation
Sealy, Inc.
Seaman Corporation
Sears Holdings Corporation
Seco Tools, Inc.
Select Medical Holdings Corporation
Selective Insurance Group, Inc.
SEMCO Energy
SemGroup Corporation
Sempra Energy
Sentara Healthcare
Sentry Group
Sentry Insurance
Serco, Inc.
Service Corporation International
The ServiceMaster Company
Seventh Generation
SFN Group, Inc.
Shands HealthCare
Sharp Electronics Corporation
Shaw Group, Inc.
Sherwin-Williams Company
Sigma Aldrich
Sigma-Aldrich Corporation
Silgan Holdings, Inc.
Simmons Bedding Company
Simon Property Group, Inc.
Sirius XM Radio, Inc.
Sitel
SJE-Rhombus
Skywest, Inc.
SLM Corporation
Smead Manufacturing Company
SMSC Gaming Enterprise
Smurfit-Stone Container Corporation
Snap-On, Inc.
Snyder's of Hanover
Solae LLC
Sole Technology, Inc.
Solo Cup Company
Solutia, Inc.
Sonic Automotive, Inc.
Sonoco Products Company
Source Interlink Companies, Inc.
South Jersey Gas Company
Southco, Inc.
Southeastern Freight Lines
Southern Company
Southern Poverty Law Center
Southern Union Company
Southwest Airlines
Southwest Gas Corporation
Southwestern Energy Company
Space Dynamics Lab
Space Telescope Science Institute
Spectra Energy Corporation
Spectrum Brands, Inc.
Spectrum Group International, Inc.
Spectrum Health – Downtown
Sprint Nextel Corporation
SPX Corporation
St. Cloud Hospital
St. John Health System
St. Jude Children's Research Hospital
St. Jude Medical, Inc.
St. Louis County Government
St. Luke's Episcopal Health System
St. Mary's at Amsterdam
St. Vincent Hospital
Stampin' Up!
Stancorp Financial Group, Inc.
Standard Motor Products, Inc.
Stanley Black & Decker, Inc.
Staples, Inc.
Starbucks Corporation
Starwood Hotels & Resorts Worldwide
State Corporation Commission
State of Oregon
State Personnel Administration
State Street Corporation
Stater Bros. Holdings, Inc.
Steel Dynamics, Inc.
Steel Technologies-Corporate
Steelcase, Inc.
Stepan Company
Sterilite Corporation
STERIS
Sterling Bank
Stewart & Stevenson
Stewart Information Services
Stonyfield Farm, Inc.
Stryker Corporation
Subuaru of Indiana Automotive, Inc.
Sulzer Pumps US, Inc.
Sun Healthcare Group, Inc.
Sun Microsystems, Inc.
Suncoast Schools Federal Credit Union
Sungard Data Systems, Inc.
Sunoco, Inc.
Sunrise Senior Living, Inc.
Sunstar Americas
Suntrust Banks, Inc.
Supermedia, Inc.
SuperValue
Susser Holdings Corporation
Sutter Health
Swiss Reinsurance
Sykes Enterprises
Symetra Financial Corporation
SYNNEX Corporation
Synovate
Synovus Financial Corporation
Synthes
SYSCO Corporation
Systemax, Inc.
T. Rowe Price Group
Targa Resources Partners LP

Target Corporation
Tastefully Simple
The Taubman Company
Taylor Corporation
TD Ameritrade Holding Corporation
TDS Telecom Corporation
Team Health Holdings, Inc.
Tech Data Corporation
TECO Energy, Inc.
Tecolote Research, Inc.
TelAlaska, Inc.
Tele-Consultants, Inc.
Teledyne Technologies, Inc.
Teleflex
Telephone & Data Systems, Inc.
Tellabs Operations, Inc.
Temple-Inland, Inc.
Tenaris, Inc.
Tenet Healthcare Corporation
Tenneco, Inc.
Teradata Corporation
Terex Corporation
Terra Industries, Inc.
Tescom Corporation
Tesoro Corporation
Tetra Tech, Inc.
Texas County & District Retirement System
Texas Industries, Inc.
Texas Instruments, Inc.
Texas Mutual Insurance Company
Textron, Inc.
Thermo Fisher Scientific, Inc.
Thomas & Betts Corporation
TI Group Automotive Systems LLC
Tiffany & Co.
The Timberland Company
Time Warner Cable
Time Warner, Inc.
TIMET
Timken Company
TJX Companies, Inc.
Toll Brothers, Inc.
Torchmark Corporation
The Toro Company
Toys R Us, Inc.
Tractor Supply Company
Travelcenters of America LLC
Travelers Companies, Inc.
Travis County
Treasure Island Resort & Casino
Tremco, Inc.
Tribune Company
Tri-Met
Trinity Health
Trinity Industries
Triple-S Management Corporation
Triwest Healthcare Alliance
TruckPro, Inc.
True Value Company
TRW Automotive Holdings Corporation
TSYS
Tufts Health Plan
Tupperware Corporation
Turner Broadcasting System, Inc.
Tutor Perini Corporation
Tyco Electronics
Tyson Foods, Inc.
UAL Corporation
UDR
UGI Corporation
UMB Bank NA
UMDNJ-University of Medicine & Dentistry
Underwriters Laboratories, Inc.
Unified Grocers, Inc.
Unified Personnel System
Unilife Corporation
Union Pacific Corporation
Unisys Corporation
United HealthCare Group
United Natural Foods, Inc.
United Parcel Service, Inc.
United Refining Company
United Rentals, Inc.
United States Steel Corporation
United Stationers, Inc.
United Technologies Corporation
United Way for Southeastern Michigan
Unitrin, Inc.
Universal American Corporation
Universal Forest Prods, Inc.
Universal Health Services
Universal Orlando
University of Alabama at Birmingham
University of Arkansas for Medical Science
The University of Chicago
University of Georgia
University of Houston
University of Kansas Hospital
University of Louisville
University of Maryland Medical Center
University of Miami
University of Michigan
University of Minnesota
University of Nebraska-Lincoln
University of Notre Dame
University of Pennsylvania
University of Rochester
University of South Florida
University of St. Thomas
University of Texas at Austin
University of Texas Health Science Center
The University of Texas M.D. Anderson Cancer Center
University of Texas Southwestern Medical Center
University of Wisconsin Medical Foundation
University Physicians, Inc.
Unum Group
UPS
Urban Outfitters, Inc.
URS Corporation
US Airways Group, Inc.
US Bancorp
US Foodservices
US Oncology Holdings, Inc.
USAA
USEC, Inc.
USG Corporation
Utah Transit Authority
Utica National Insurance
Vail Resorts Management Company
Valassis Communications, Inc.
Valero Energy Corporation
Valhi, Inc.
Valmont Industries, Inc.
Van Andel Institute
Vangent, Inc.
Varian Medical Systems, Inc.
Vectren Corporation
Venetian Resort-Hotel-Casino
Ventura Foods LLC
Venturedyne, Ltd.
Verde Realty
Verizon Communications, Inc.
Vermeer Manufacturing Company
VF Corporation
Via Christi Regional Medical Center
Viacom, Inc.
Viant Health Payment Solutions
Viejas Enterprise
Virgin Media, Inc.
Visa, Inc.
Vishay Intertechnology, Inc.
Visiting Nurse Association of the Inland Counties
Visiting Nurse Service of New York
Visteon Corporation
Volvo Group North America
Vornado Realty Trust
Vought Aircraft Industries, Inc.
Vulcan Materials Company
W C Bradley Company
W R Grace & Company
W.R. Berkley Corporation
W.W. Grainger, Inc.
Wackenhut Services, Inc.
Wake County Government
Walgreen Company
Wal-Mart Stores, Inc.
Walt Disney Company
Walter Energy
Warnaco Group, Inc.
Warner Music Group Corporation
Washington Post
Washington Suburban Sanitary Commission
Washington University in St. Louis
Waste Industries, Inc.
Waste Management, Inc.
Watsco, Inc.
Watson Pharmaceuticals, Inc.
Wawa, Inc.
Wayne Memorial Hospital
Wellcare Health Plans
Wellmark BlueCross BlueShield
Wellpoint, Inc.
Wendy's/Arby's Group, Inc.
Werner Company
Werner Enterprises, Inc.
WESCO International, Inc.
West Penn Allegheny Health System
West Pharmaceutical Services
West Virginia University Hospitals, Inc.
Westar Energy, Inc.
Western Refining, Inc.
Western Southern Financial Group
Western Textile Companies
Western Union Company
Westfield Group
Westlake Chemical Corporation
Weston Solutions, Inc.
Weyerhaeuser Company
WGL Holdings, Inc.
Wheaton Franciscan Healthcare
Wheels, Inc.
Whirlpool Corporation
Whole Foods Market, Inc.
Wilbur Smith Associates
The Wilder Foundation
Williams Companies, Inc.
Williams-Sonoma, Inc.
Wilmer Hale
Wilsonart International
Windstream Communications
Winn-Dixie Stores, Inc.
Winpak Portion Packaging, Ltd.
Wisconsin Energy Corporation
Wisconsin Physicians Service Insurance Corporation
Wolverine World Wide, Inc.
World Fuel Services Corporation
World Vision International
Worthington Industries
Wyle Laboratories
Wyndham Worldwide Corporation
Wynn Resorts, Ltd.

Xcel Energy, Inc.
Xerox Corporation
Yahoo, Inc.
Yamaha Corporation of America
Yankee Candle Company
YKK Corporation of America
YSI
Yum Brands, Inc.
Zale Corporation
Zeon Chemicals LP
Zimmer, Inc.
Zions Bancorporation

EXHIBIT B

Companies Surveyed using Equilar, Inc.
MDU Resources Group, Inc. – President & Chief Executive Officer
Competitive Analysis to Determine Base Salary, Target Annual Cash Compensation, and Target Total Direct Compensation

AGL Resources Inc.
Alliant Energy Corp.
Ameren Corp.
ARC Resources Ltd.
Atmos Energy Corp.
Avista Corp.
Berry Petroleum Co.
Black Hills Corp.
Boardwalk Pipeline Partners, LP
Chicago Bridge & Iron Co.
Cimarex Energy Co.
CMS Energy Corp.
Comfort Systems USA Inc.
Compass Minerals International Inc.
Complete Production Services, Inc.
Comstock Resources Inc.
DCP Midstream Partners, LP
Denbury Resources Inc.
Diamond Offshore Drilling, Inc.
DPL Inc.
El Paso Corp.
EMCOR Group, Inc.
Energen Corp.
Energy Transfer Equity, L.P.
Enerplus Corp.
Ensco plc
EOG Resources, Inc.
EQT Corp.
Foster Wheeler AG
Granite Construction Inc.
Helix Energy Solutions Group, Inc.
Helmerich & Payne, Inc.
Integrys Energy Group, Inc.
Key Energy Services Inc.
Laclede Group, Inc.
Layne Christenson Co.
MarkWest Energy Partners, L.P.
Martin Marietta Materials, Inc.
MasTec, Inc.
Nabors Industries Ltd.
National Fuel Gas Co.
New Jersey Resources Corp.
Newfield Exploration Co.
Nexen Inc.
Nicor Inc.
NiSource Inc.
Noble Corp.
Noble Energy Inc.
Northwest Natural Gas Co.
NorthWestern Corp.
NV Energy Inc.
Oceaneering International Inc.
Patterson UTI Energy Inc.
Pengrowth Energy Corp.
Penn West Petroleum Ltd.
Pepco Holdings, Inc.
Petrohawk Energy Corp.
Piedmont Natural Gas Co. Inc.
Pike Electric Corp.
Pioneer Natural Resources Co.
Plains Exploration & Production Co.
Precision Drilling Corp.
Pride International Inc.
QEP Resources, Inc.
Quanta Services, Inc.
Questar Corp.
Range Resources Corp.
Regency Energy Partners LP
Rowan Companies Inc.
RPC Inc.
SCANA Corp.
SM Energy Co.
Southern Union Co.
Southwest Gas Corp.
Southwestern Energy Co.
Spectra Energy Corp.
Sterling Construction Co. Inc.
Superior Energy Services Inc.
Swift Energy Co.
Talisman Energy Inc.
Targa Resources Partners LP
Texas Industries Inc.
TransCanada Corp.
UGI Corp.
USEC Inc.
Vectren Corp.
Vulcan Materials Co.
Westar Energy Inc.
WGL Holdings, Inc.
Whiting Petroleum Corp.
Willbros Group, Inc.
Wisconsin Energy Corp.

Companies Surveyed using Equilar, Inc.
MDU Resources Group, Inc. – Vice President & Chief Financial Officer
Competitive Analysis to Determine Base Salary, Target Annual Cash Compensation, and Target Total Direct Compensation

Alliant Energy Corp.
Ameren Corp.
ARC Resources Ltd.
Atmos Energy Corp.
Avista Corp.
Berry Petroleum Co.
BJ Services Co.
Black Hills Corp.
Chicago Bridge & Iron Co.
Cimarex Energy Co.
CMS Energy Corp.
Comfort Systems USA Inc.
Compass Minerals International Inc.
Complete Production Services, Inc.
Comstock Resources Inc.
Denbury Resources Inc.
Diamond Offshore Drilling, Inc.
DPL Inc.
EMCOR Group, Inc.
Enerplus Corp.
Ensco plc
EOG Resources, Inc.
EQT Corp.
Foster Wheeler AG
Granite Construction Inc.
Helix Energy Solutions Group, Inc.
Helmerich & Payne, Inc.
Integrys Energy Group, Inc.
Key Energy Services Inc.
Layne Christenson Co.
MarkWest Energy Partners, L.P.
Martin Marietta Materials, Inc.
MasTec, Inc.
Nabors Industries Ltd.
National Fuel Gas Co.
Newfield Exploration Co.
Nexen Inc.
NiSource Inc.
Noble Corp.
Noble Energy Inc.
Northwest Natural Gas Co.
NorthWestern Corp.
NV Energy Inc.
Oceaneering International Inc.
Patterson UTI Energy Inc.
Pengrowth Energy Corp.
Penn West Petroleum Ltd.
Pepco Holdings, Inc.
Petrohawk Energy Corp.
Pike Electric Corp.
Pioneer Natural Resources Co.
Plains Exploration & Production Co.
Precision Drilling Corp
Pride International Inc.
QEP Resources, Inc.
Quanta Services, Inc.
Questar Corp.
Range Resources Corp.
Regency Energy Partners LP
Rowan Companies Inc.
RPC Inc.
SCANA Corp.
SM Energy Co.
Southern Union Co.
Southwest Gas Corp.
Southwestern Energy Co.
Sterling Construction Co. Inc.
Superior Energy Services Inc.
Swift Energy Co.
Talisman Energy Inc.
Texas Industries Inc.
UGI Corp.
USEC Inc.
Vectren Corp.
Vulcan Materials Co.
Westar Energy Inc.
Whiting Petroleum Corp.
Willbros Group, Inc.
Wisconsin Energy Corp.

Companies Surveyed using Equilar, Inc.
Exploration and Production Segment – President & Chief Executive Officer
Competitive Analysis to Determine Base Salary, Target Annual Cash Compensation, and Target Total Direct Compensation

Advantage Oil & Gas Ltd.
ATP Oil & Gas Corp.
Atwood Oceanics Inc.
Berry Petroleum Co.
Bill Barrett
BreitBurn Energy Partners L.P.
Cabot Oil & Gas Corp.
Cheniere Energy, Inc.
Clayton Williams Energy, Inc.
Comstock Resources Inc
Continental Resources Inc.
Eagle Rock Energy Partners L.P.
Energy XXI (Bermuda) Ltd.
EQT Corp.
EXCO Resources Inc.
Geokinetics Inc.
Global Geophysical Services Inc.
Gran Tierra Energy Inc.
Hercules Offshore, Inc.
Ion Geophysical
Linn Energy, LLC
Parker Drilling Co.
Penn Virginia Corp.
Petroleum Development Corp.
Pioneer Drilling Co.
Rosetta Resources Inc.
SM Energy Co.
Stone Energy Corp.
Swift Energy Co.
Vantage Drilling Co.
Venoco, Inc.
W&T Offshore Inc.
Whiting Petroleum Corp.

Companies Surveyed using Equilar, Inc.
Pipeline and Energy Services Segment – President & Chief Executive Officer
Competitive Analysis to Determine Base Salary, Target Annual Cash Compensation, and Target Total Direct Compensation

Atlas Pipeline Partners, L.P.
Basic Energy Services, Inc.
Cal Dive International, Inc.
Chesapeake Utilities Corporation
Copano Energy, L.L.C.
Core Laboratories Inc.
Delta Natural Gas Company, Inc.
Dune Energy, Inc.
Global Industries, Ltd.
National Fuel Gas Co.
Natural Gas Services Group, Inc.
Northwest Natural Gas Co.
Questar Corp.
RGC Resources, Inc.
South Jersey Industries, Inc.
Southern Union Co.
Western Gas Partners, LP

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Corporate Headquarters
MDU Resources Group, Inc.
Street Address: 1200 W. Century Ave.
Bismarck, ND 58503

Mailing Address: P.O. Box 5650
Bismarck, ND 58506-5650

Telephone: (701) 530-1000
Toll-Free Telephone: (866) 760-4852
www.mdu.com

The company has filed as exhibits to its Annual Report on Form 10-K the CEO and CFO certifications as required by Section 302 of the Sarbanes-Oxley Act.

The company also submitted the required annual CEO certification to the New York Stock Exchange.

Common Stock
MDU Resources' common stock is listed on the NYSE under the symbol MDU. The stock began trading on the NYSE in 1948 and is included in the Standard & Poor's MidCap 400 index. Average daily trading volume in 2012 was 645,831 shares.

Common Stock Prices

	High	Low	Close
2012			
First Quarter	$22.50	$21.14	$22.39
Second Quarter	23.21	20.76	21.61
Third Quarter	23.11	21.42	22.04
Fourth Quarter	22.23	19.59	21.24
2011			
First Quarter	$23.00	$20.11	$22.97
Second Quarter	24.05	21.47	22.50
Third Quarter	23.28	18.25	19.19
Fourth Quarter	22.19	18.00	21.46

Dividend Reinvestment and Direct Stock Purchase Plan
The company's plan provides interested investors the opportunity to purchase shares of the company's common stock and to reinvest dividends without incurring brokerage commissions. For complete details, including an enrollment form, contact the stock transfer agent. Plan information also is available on the Wells Fargo Shareowner Services website: www.shareowneronline.com.

2013 Key Dividend Dates

	Ex-Dividend Date	Record Date	Payment Date
First Quarter	March 12	March 14	April 1
Second Quarter	June 11	June 13	July 1
Third Quarter	September 10	September 12	October 1
Fourth Quarter	December 10	December 12	January 1, 2014

Key dividend dates are subject to the discretion of the Board of Directors.

Annual Meeting
Tuesday, April 23, 2013
11 a.m. CDT
Montana-Dakota Utilities Co. Service Center
909 Airport Road
Bismarck, North Dakota

Shareholder Information and Inquiries
Registered shareholders have electronic access to their accounts by visiting www.shareowneronline.com. Shareowner Online allows shareholders to view their account balance, dividend information, reinvestment details and more. The stock transfer agent maintains stockholder account information.

Communications regarding stock transfer requirements, lost certificates, dividends or change of address should be directed to the stock transfer agent.

Company information, including financial reports, is available at www.mdu.com.

Shareholder Contact
Dustin J. Senger
Telephone: (866) 866-8919
Email: investor@mduresources.com

Analyst Contact
Phyllis A. Rittenbach
Director of Investor Relations
Telephone: (701) 530-1057
Email: phyllis.rittenbach@mduresources.com

Transfer Agent and Registrar for All Classes of Stock and Dividend Reinvestment Plan
Wells Fargo Bank, N.A.
Stock Transfer Department
P.O. Box 64874
St. Paul, MN 55164-0874
Telephone: (651) 450-4064
Toll-Free Telephone: (877) 536-3553
www.shareowneronline.com

Transfer Agent and Registrar for Senior Notes
The Bank of New York Mellon
Corporate Trust Department
101 Barclay St. – 12W
New York, NY 10286

Independent Auditors
Deloitte & Touche LLP
50 S. Sixth St., Suite 2800
Minneapolis, MN 55402-1538

Note: This information is not given in connection with any sale or offer for sale or offer to buy any security.

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Bismarck, ND 58506-5650

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(866) 760-4852

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Trading Symbol: MDU

www.mdu.com