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 Stockh

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 Enter statute number
☐ Order Enter PUC Order No
☐ Other Enter reason

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 2013/Q4

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).

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QUARTERLY/ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent Cascade Natural Gas Corporation	Year/Period of Report End of 2013/Q4	
03 Previous Name and Date of Change (If name changed during year)		
04 Address of Principal Office at End of Year (Street, City, State, Zip Code) 8113 West Grandridge Boulevard, Kennewick, WA 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, WA 99336-7166		
08 Telephone of Contact Person, Including Area Code 509-734-4516	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 12/31/2013

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 03/21/2014

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 (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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."

List of Schedules (Natural Gas Company) (continued)

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 (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

General Information

1. Provide 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 the general corporate books are kept.

Tammy Nygard
Director, Accounting & Finance
8113 West Grandridge Boulevard
Kennewick, Washington 99336-7166

2. Provide the name of the State under the laws of which respondent is incorporated and 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 trusteeship 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 engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 trustees, 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	DE	100.00
2	MDU Energy Capital, LLC	I	DE	100.00
3	Praire Cascade Energy Holdings, LLC (PCEH)	D	DE	100.00
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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, an "I" for indirect, or a "J" for joint control.

DEFINITIONS

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1. See the Uniform System of Accounts for a 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 that 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	*Not used*
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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, warrants, 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, or rights were

1. Give date of the latest closing of the stock book prior to end of year, and, in a footnote, 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:	

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 listed below	1,000	1,000		
8					
9					
10					
11	Cascade is a wholly-owned subsidiary of MDU Resources Group, Inc.				
12					
13					
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15					
16					
17					
18					
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) X An Original (2) __ A Resubmission	12/31/2013	2013/Q4

Important Changes During the Quarter/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.

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 2013.
9. None
10. None
11. None
12. K. Frank Morehouse, President and Chief Executive Officer; Scott W. Madison, Executive Vice President and General Manager; Mark A. Chiles, Vice President, Controller, Assistant Treasurer and Assistant Secretary.
13. None

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[Next page is 110]

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	767,957,540	737,323,182
3	Construction Work in Progress (107)	200-201	12,554,927	17,556,051
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	780,512,467	754,879,233
5	(Less) Accum. Provision for Depr., Amort., Depl. (108, 111, 115)		385,942,905	372,642,118
6	Net Utility Plant (Total of line 4 less 5)		394,569,562	382,237,115
7	Nuclear Fuel (120.1 thru 120.4, and 120.6)		0	0
8	(Less) Accum. Provision for Amort., of Nuclear Fuel Assemblies (120.5)		0	0
9	Nuclear Fuel (Total of line 7 less 8)		0	0
10	Net Utility Plant (Total of lines 6 and 9)		394,569,562	382,237,115
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored-Base Gas (117.1)	220	0	0
13	System Balancing Gas (117.2)	220	0	0
14	Gas Stored in Reservoirs and Pipelines-Noncurrent (117.3)	220	0	0
15	Gas Owed to System Gas (117.4)	220	0	0
16	**OTHER PROPERTY AND INVESTMENTS**			
17	Nonutility Property (121)		202,030	202,030
18	(Less) Accum. Provision for Depreciation and Amortization (122)		0	0
19	Investments in Associated Companies (123)	222-223	0	0
20	Investments in Subsidiary Companies (123.1)	224-225	0	0
21	(For Cost of Account 123.1 See Footnote Page 224, line 40)			
22	Noncurrent Portion of Allowances		0	0
23	Other Investments (124)	222-223	10,095,569	9,739,905
24	Sinking Funds (125)		0	0
25	Depreciation Fund (126)		0	0
26	Amortization Fund - Federal (127)		0	0
27	Other Special Funds (128)		0	0
28	Long-Term Portion of Derivative Assets (175)		0	0
29	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
30	TOTAL Other Property and Investments (Total of lines 17-20, 22-29)		10,297,599	9,941,935
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)		2,022,453	418,834
33	Special Deposits (132-134)		0	0
34	Working Funds (135)		2,900	2,800
35	Temporary Cash Investments (136)	222-223	0	0
36	Notes Receivable (141)		51,812	112,752
37	Customer Accounts Receivable (142)		16,894,569	9,183,809
38	Other Accounts Receivable (143)		402,611	1,320,446
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		527,021	697,075
40	Notes Receivable from Associated Companies (145)		0	0
41	Accounts Receivable from Associated Companies (146)		123,269	60,314
42	Fuel Stock (151)		0	0
43	Fuel Stock Expenses Undistributed (152)		0	0

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 Products (Gas) (153)		0	0
45	Plant Materials and Operating Supplies (154)		6,093,326	5,943,723
46	Merchandise (155)		0	0
47	Other Materials and Supplies (156)		0	0
48	Nuclear Materials Held for Sale (157)		0	0
49	Allowances (158.1 and 158.2)		0	0
50	(Less) Noncurrent Portion of Allowances		0	0
51	Stores Expense Undistributed (163)		0	0
52	Gas Stored Underground-Current (164.1)	220	960,973	0
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220	2,893,474	3,166,527
54	Prepayments (165)	230	4,750,729	4,618,893
55	Advances for Gas (166 thru 167)		0	0
56	Interest and Dividends Receivable (171)		0	0
57	Rents Receivable (172)		0	0
58	Accrued Utility Revenues (173)		32,266,682	23,485,734
59	Miscellaneous Current and Accrued Assets (174)		0	0
60	Derivative Instrument Assets (175)		0	0
61	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
62	Derivative Instrument Assets - Hedges (176)		0	0
63	(Less) Long-Term Portion of Derivative Instrument Assests - Hedges (176)		0	0
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)		65,935,777	47,616,757
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)		2,303,125	1,927,485
67	Extraordinary Property Losses (182.1)	230	0	0
68	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
69	Other Regulatory Assets (182.3)	232	36,052,147	55,900,905
70	Preliminary Survey and Investigation Charges (Electric)(183)		0	0
71	Preliminary Survey and Investigation Charges (Gas)(183.1 and 183.2)		0	0
72	Clearing Accounts (184)		(100,767)	(102,840)
73	Temporary Facilities (185)		0	0
74	Miscellaneous Deferred Debits (186)	233	19,813,630	21,172,748
75	Deferred Losses from Disposition of Utility Plant (187)		0	0
76	Research, Development, and Demonstration Expend. (188)		0	0
77	Unamortized Loss on Reacquired Debt (189)		949,154	1,016,943
78	Accumulated Deferred Income Taxes (190)	234-235	20,926,644	27,838,248
79	Unrecovered Purchased Gas Costs (191)		0	0
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		79,943,933	107,753,489
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		550,746,871	547,549,296

Comparative Balance Sheet (Liabilities and Other Credits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	1,000	1,000
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	117,703,952	117,703,952
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	47,283,729	48,284,212
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	0	0
13	(Less) Reacquired Capital Stock (217)	250-251	0	0
14	Accumulated Other Comprehensive Income (219)	117	0	0
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)		164,988,681	165,989,164
16	**LONG TERM DEBT**			
17	Bonds (221)	256-257	0	0
18	(Less) Reacquired Bonds (222)	256-257	0	0
19	Advances from Associated Companies (223)	256-257	0	0
20	Other Long-Term Debt (224)	256-257	164,863,000	115,090,000
21	Unamortized Premium on Long-Term Debt (225)	258-259	0	0
22	(Less) Unamortized Discount on Long-Term Debt-Dr (226)	258-259	0	0
23	(Less) Current Portion of Long-Term Debt		0	0
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)		164,863,000	115,090,000
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases-Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		13,346,221	14,389,869
29	Accumulated Provision for Pensions and Benefits (228.3)		6,562,655	11,878,086
30	Accumulated Miscellaneous Operating Provisions (228.4)		24,135	17,960
31	Accumulated Provision for Rate Refunds (229)		0	0

Comparative Balance Sheet (Liabilities and Other Credits)(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance	Prior Year End Balance 12/31 (d)
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		569,829	547,358
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		20,502,840	26,833,273
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-Term Debt		0	24,000,000
38	Notes Payable (231)		11,500,000	2,000,000
39	Accounts Payable (232)		29,068,725	23,561,296
40	Notes Payable to Associated Companies (233)		0	0
41	Accounts Payable to Associated Companies (234)		1,500,660	1,646,553
42	Customer Deposits (235)		1,749,584	2,065,287
43	Taxes Accrued (236)	262-263	9,299,598	7,581,014
44	Interest Accrued (237)		2,260,220	2,370,713
45	Dividends Declared (238)		4,160,000	0
46	Matured Long-Term Debt (239)		0	0
47	Matured Interest (240)		0	0
48	Tax Collections Payable (241)		3,002	(177)
49	Miscellaneous Current and Accrued Liabilities (242)	268	7,601,991	6,609,634
50	Obligations Under Capital Leases-Current (243)		0	0
51	Derivative Instrument Liabilities (244)		0	0
52	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
53	Derivative Instrument Liabilities - Hedges (245)		0	0
54	(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
55	TOTAL Current and Accrued Liabilities (Total of lines 37 thru 54)		67,143,780	69,834,320
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)		4,296,051	4,620,155
58	Accumulated Deferred Investment Tax Credits (255)		483,242	546,530
59	Deferred Gains from Disposition of Utility Plant (256)		0	0
60	Other Deferred Credits (253)	269	11,513,466	50,631,548
61	Other Regulatory Liabilities (254)	278	4,652,943	4,230,506
62	Unamortized Gain on Reacquired Debt (257)	260	0	0
63	Accumulated Deferred Income Taxes - Accelerated Amortization (281)		0	0
64	Accumulated Deferred Income Taxes - Other Property (282)		84,106,817	77,797,048
65	Accumulated Deferred Income Taxes - Other (283)		28,196,051	31,976,752
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		133,248,570	169,802,539
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		550,746,871	547,549,296

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 Number (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	279,314,948	276,988,483	0	0
3	Operating Expenses					
4	Operation Expenses (401)	317-325	193,471,588	193,328,100	0	0
5	Maintenance Expenses (402)	317-325	5,588,163	5,114,841	0	0
6	Depreciation Expense (403)	336-338	19,158,714	18,451,177	0	0
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-338	0	0	0	0
8	Amortization and Depletion of Utility Plant (404-405)	336-338	1,523,238	923,958	0	0
9	Amortization of Utility Plant Acu. Adjustment (406)	336-338	0	0	0	0
10	Amort. of Prop. Losses, Unrecovered Plant and Reg. Study Costs (407.1)		0	0	0	0
11	Amortization of Conversion Expenses (407.2)		0	0	0	0
12	Regulatory Debits (407.3)		0	368,759	0	0
13	(Less) Regulatory Credits (407.4)		0	0	0	0
14	Taxes Other than Income Taxes (408.1)	262-263	26,541,850	26,801,066	0	0
15	Income Taxes-Federal (409.1)	262-263	(481,297)	(1,253,216)	0	0
16	Income Taxes-Other (409.1)	262-263	(41,718)	(87,115)	0	0
17	Provision of Deferred Income Taxes (410.1)	234-235	9,098,512	8,815,956	0	0
18	(Less) Provision for Deferred Income Taxes-Credit (411.1)	234-235	0	0	0	0
19	Investment Tax Credit Adjustment-Net (411.4)		(63,288)	(18,268)	0	0
20	(Less) Gains from Disposition of Utility Plant (411.6)		0	0	0	0
21	Losses from Disposition of Utility Plant (411.7)		0	0	0	0
22	(Less) Gains from Disposition of Allowances (411.8)		0	0	0	0
23	Losses from Disposition of Allowances (411.9)		0	0	0	0
24	Accretion Expense (411.10)		0	0	0	0
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)		254,795,762	252,445,258	0	0
26	Net Utility Operating Income (Total of lines 2 less 25) (Carry forward to page 116, line 27)		24,519,186	24,543,225	0	0

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	0	0	279,314,948	276,988,483	0	0
3						
4	0	0	193,471,588	193,328,100	0	0
5	0	0	5,588,163	5,114,841	0	0
6	0	0	19,158,714	18,451,177	0	0
7	0	0	0	0	0	0
8	0	0	1,523,238	923,958	0	0
9	0	0	0	0	0	0
10	0	0	0	0	0	0
11	0	0	0	0	0	0
12	0	0	0	368,759	0	0
13	0	0	0	0	0	0
14	0	0	26,541,850	26,801,066	0	0
15	0	0	(481,297)	(1,253,216)	0	0
16	0	0	(41,718)	(87,115)	0	0
17	0	0	9,098,512	8,815,956	0	0
18	0	0	0	0	0	0
19	0	0	(63,288)	(18,268)	0	0
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	0	0	0	0	0	0
23	0	0	0	0	0	0
24	0	0	0	0	0	0
25	0	0	254,795,762	252,445,258	0	0
26	0	0	24,519,186	24,543,225	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Statement of Income(continued)

Line No.	Title of Account (a)	Reference Page Number (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 forward from page 114)		24,519,186	24,543,225	0	0
28	OTHER INCOME AND DEDUCTIONS					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues form Merchandising, Jobbing and Contract Work (415)		0	0	0	0
32	(Less) Costs and Expense of Merchandising, Job & Contract Work (416)		0	0	0	0
33	Revenues from Nonutility Operations (417)		22,912	14,974	0	0
34	(Less) Expenses of Nonutility Operations (417.1)		0	0	0	0
35	Nonoperating Rental Income (418)		0	0	0	0
36	Equity in Earnings of Subsidiary Companies (418.1)	119	0	0	0	0
37	Interest and Dividend Income (419)		201,519	254,357	0	0
38	Allowance for Other Funds Used During Construction (419.1)		(563)	464,259	0	0
39	Miscellaneous Nonoperating Income (421)		23,112	23,623	0	0
40	Gain on Disposition of Property (421.1)		0	0	0	0
41	TOTAL Other Income (Total of lines 31 thru 40)		246,980	757,213	0	0
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		0	0	0	0
44	Miscellaneous Amortization (425)		0	0	0	0
45	Donations (426.1)	340	210,111	221,908	0	0
46	Life Insurance (426.2)		0	0	0	0
47	Penalties (426.3)		679	0	0	0
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		113,169	109,581	0	0
49	Other Deductions (426.5)		40	60	0	0
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)	340	323,999	331,549	0	0
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other than Income Taxes (408.2)	262-263	2,604	3,638	0	0
53	Income Taxes-Federal (409.2)	262-263	1,503	2,586	0	0
54	Income Taxes-Other (409.2)	262-263	137	180	0	0
55	Provision for Deferred Income Taxes (410.2)	234-235	0	0	0	0
56	(Less) Provision for Deferred Income Taxes-Credit (411.2)	234-235	0	0	0	0
57	Investment Tax Credit Adjustments-Net (411.5)		0	0	0	0
58	(Less) Investment Tax Credits (420)		0	0	0	0
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		4,244	6,404	0	0
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(81,263)	419,260	0	0
61	INTEREST CHARGES					
62	Interest on Long-Term Debt (427)		7,578,332	10,155,023	0	0
63	Amortization of Debt Disc. and Expense (428)	258-259	128,814	120,628	0	0
64	Amortization of Loss on Reacquired Debt (428.1)		67,790	249,054	0	0
65	(Less) Amortization of Premium on Debt-Credit (429)	258-259	0	0	0	0
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)		0	0	0	0
67	Interest on Debt to Associated Companies (430)	340	0	0	0	0
68	Other Interest Expense (431)	340	1,258,825	1,342,152	0	0
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)		263,260	288,422	0	0
70	Net Interest Charges (Total of lines 62 thru 69)		8,770,501	11,578,435	0	0
71	Income Before Extraordinary Items (Total of lines 27,60 and 70)		15,667,422	13,384,050	0	0
72	EXTRAORDINARY ITEMS					
73	Extraordinary Income (434)		0	0	0	0
74	(Less) Extraordinary Deductions (435)		0	0	0	0
75	Net Extraordinary Items (Total of line 73 less line 74)		0	0	0	0
76	Income Taxes-Federal and Other (409.3)	262-263	0	0	0	0
77	Extraordinary Items after Taxes (Total of line 75 less line 76)		0	0	0	0
78	Net Income (Total of lines 71 and 77)		15,667,422	13,384,050	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 of report Dec. 31, 2013

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	-	-	24,519,186	24,543,225	-	-
28	[redacted]					
29						
30						
31	-	-	-	-	-	-
32	-	-	-	-	-	-
33	-	-	22,912	14,974	-	-
34	-	-	-	-	-	-
35	-	-	-	-	-	-
36	-	-	-	-	-	-
37	-	-	201,519	254,357	-	-
38	-	-	(563)	464,259	-	-
39	-	-	23,112	23,623	-	-
40	-	-	-	-	-	-
41	-	-	246,980	757,213	-	-
42	[redacted]					
43			-	-		
44			-	-		
45			210,111	221,908		
46			-	-		
47			679	-		
48			113,169	109,581		
49	-	-	40	60	-	-
50	-	-	323,999	331,549	-	-
51	[redacted]					
52			2,604	3,638		
53	-	-	1,503	2,586	-	-
54	-	-	137	180	-	-
55	-	-	-	-	-	-
56	-	-	-	-	-	-
57	-	-	-	-	-	-
58	-	-		-	-	-
59	-	-	4,244	6,404	-	-
60	-	-	(81,263)	419,260	-	-
61	[redacted]					
62	-	-	7,578,332	10,155,023	-	-
63	-	-	128,814	120,628	-	-
64	-	-	67,790	249,054	-	-
65	-	-	-	-	-	-
66	-	-	-	-	-	-
67	-	-	-	-	-	-
68	-	-	1,258,825	1,342,152	-	-
69	-	-	(263,260)	(288,422)	-	-
70	-	-	8,770,501	11,578,435	-	-
71	-	-	15,667,422	13,384,050	-	-
72	[redacted]					
73	-	-	-	-	-	-
74	-	-	-	-	-	-
75	-	-	-	-	-	-
76	-	-	-	-	-	-
77	-	-	-	-	-	-
78	-	-	15,667,422	13,384,050	-	-

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Statement of Accumulated Comprehensive Income and Hedging Activities

1. Report in columns (b) (c) and (e) the amounts of accumulated 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 available-for-sale securities (b)	Minimum Pension liabililty 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 Reclassifications 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 Quarter/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					
2					
3					
4				13,384,050	13,384,050
5					
6					
7					
8					
9				15,667,422	15,667,422
10					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 Quarter Year to Date Balance (c)	Previous Quarter Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS			
1	Balance-Beginning of Period		48,284,212	51,007,810
2	Changes (Identify by prescribed retained earnings accounts)			
3	Adjustments to Retained Earnings (Account 439)			
4	TOTAL Credits to Retained Earnings (Account 439) (footnote details)			
5	TOTAL Debits to Retained Earnings (Account 439) (footnote details)			
6	Balance Transferred from Income (Acct 433 less Acct 418.1)		15,667,422	13,384,050
7	Appropriations of Retained Earnings (Account 436)			
8	TOTAL Appropriations of Retained Earnings (Account 436) (footnote details)			
9	Dividends Declared-Preferred Stock (Account 437)			
10	TOTAL Dividends Declared-Preferred Stock (Account 437) (footnote details)			
11	Dividends Declared-Common Stock (Account 438)			
12	TOTAL Dividends Declared-Common Stock (Account 438) (footnote details)		16,667,905	16,107,648
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)		47,283,729	48,284,212
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		47,283,729	48,284,212
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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[Next page is 120]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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) Identify 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 reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 25) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

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)	16,508,977	13,384,050
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	20,681,952	19,375,135
5	Amortization of (Specify) (footnote details): Gas cost changes	(22,163,001)	(394,385)
6	Deferred Income Taxes (Net)	8,301,947	8,815,956
7	Investment Tax Credit Adjustments (Net)	63,288	(18,268)
8	Net (Increase) Decrease in Receivables	(14,194,780)	12,220,023
9	Net (Increase) Decrease in Inventory	(837,523)	3,663,866
10	Net (Increase) Decrease in Allowances Inventory		
11	Net Increase (Decrease) in Payables and Accrued Expenses	5,795,910	(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 Subsidiary Companies		
16	Other (footnote details): Net change in other deferred balances	(1,510,601)	(2,414,524)
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of Lines 2 thru 16)	12,646,169	45,451,678
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(33,608,449)	(38,577,286)
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	(563)	464,259
27	Other (footnote details): Net increase in customer advances for construction	(324,104)	(1,613,927)
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(33,931,990)	(40,655,472)
29			
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)	(455,629)	7,222,164
32			
33	Investments in and Advances to Assoc. and Subsidiary Companies		
34	Contributions and Advances from Assoc. and 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)		

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		
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 (footnote details): SERP Assets	552,169	(260,669)
48	Net Cash Provided by (Used in) Investing Activities		
49	(Total of lines 28 thru 47)	(33,835,450)	(33,693,977)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)	50,000,000	
54	Preferred Stock		
55	Common Stock		
56	Other (footnote details):		
57	Net Increase in Short-term Debt (c)	9,500,000	2,000,000
58	Other (footnote details):		
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	59,500,000	2,000,000
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)	(24,227,000)	(22,379,000)
63	Preferred Stock		
64	Common Stock		
65	Other (footnote details):		
66	Net Decrease in Short-Term Debt (c)		
67			
68	Dividends on Preferred Stock		
69	Dividends on Common Stock	(12,480,000)	(19,990,000)
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of lines 59 thru 69)	22,793,000	(40,369,000)
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of line 18, 49 and 71)	1,603,719	(28,611,299)
75			
76	Cash and Cash Equivalents at Beginning of Period	421,634	29,032,933
77			
78	Cash and Cash Equivalents at End of Period	2,025,353	421,634

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 reversions of assets. Entities that participate in multiemployer postretirement benefit plans (e.g. parent company sponsored pension 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 which 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 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 item. 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 sufficient 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 effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings 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 instructions, such notes may be included herein.

The accompanying notes related 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, 2013 and 2012

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 over 596,000 residential, commercial and industrial customers in 170 communties. 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.

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 operating expenses.

Management has also evaluated the impact of events occurring after December 31, 2013, up to the date of the issuance of these consolidated financial statements on April 1, 2014, that would require recognition or disclosure in the financial statements. For more information on subsequent events, see Note 12.

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 $803,000 and $1.1 million as of December 31, 2013 and 2012, 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, 2013 and 2012, was $971,000 and $926,000, respectively.

Inventories and natural gas in storage
Inventories, other than natural gas in storage, consisted of materials and supplies of $8.6 million and $8.1 million as of December 31, 2013 and 2012, 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 $8.9 million and $7.9 million at December 31, 2013 and 2012, respectively.

Investments
The Company's investments include the cash surrender value of life insurance policies and an insurance contract. The Company measures its investment in the insurance contract at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. For more information, see Notes 4 and 8.

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 $750,000 for the year ended December 31, 2013 and $1.9 million for the year ended December 31, 2012. 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, which is included in other regulatory liabilities-noncurrent.

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

	2013	2012	Weighted Average Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Distribution plant	**$ 1,036,420**	$ 1,000,224	40
Transmission plant	**89,239**	83,891	51
Storage plant	**17,022**	16,505	38
General plant	**93,576**	94,247	16
Other plant	**27,775**	19,508	15
Non-depreciable plant	**6,286**	6,093	-
Construction in progress	**36,544**	38,290	-
Less: Accumulated depreciation and amortization	**484,657**	469,804	
Net property, plant and equipment	**$ 822,205**	$ 788,954	

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 2013 and 2012. 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. 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, 2013 and 2012, there were no impairment losses recorded. At December 31, 2013, the fair value substantially 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 5 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 2013. 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 $57.7 million and $46.5 million at December 31, 2013 and 2012, 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.

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 6.

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 over a 12 month period. Natural gas costs refundable through rate adjustments were $16.9 million and $35.3 million at December 31, 2013 and 2012, respectively. Natural gas costs recoverable through rate adjustments were $4.0 million at December 31, 2013.

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 made basis. Cascade and Intermountain are retaining losses within respective retentions 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; and asset retirement obligations. 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:

	2013	2012
	(In thousands)	
Interest, net of amount capitalized	**$ 19,845**	$ 22,701
Income taxes refunded, net	**$ (5,657)**	$ (3,196)

Noncash investing transactions at December 31 were as follows:

	2013	2012
	(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 1,838**	$ 11,949

New accounting standards

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. In January 2013, the FASB issued guidance clarifying the scope of the disclosures related to balance sheet offsetting. The amendments clarify that this guidance only applies to derivative instruments, repurchase agreements and securities lending transactions that are either offset or subject to an enforceable master netting arrangement. The guidance was effective for the Company on January 1, 2013 and must be applied retrospectively. The guidance required additional disclosures, however it did 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, 2013 and 2012 remained unchanged at $340,924. No impairments of goodwill have been recorded.

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 *	**2013**	2012
		(In thousands)	
Regulatory assets:			
Deferred income taxes	**	**$ 75,476**	$ 72,951
Pension and postretirement benefits (a)	(c)	**37,993**	61,825
Manufactured gas plant remediation (a)	Determined upon filing	**15,434**	15,374
Taxes recoverable from customers (a)	Over plant lives	**6,593**	9,078
Natural gas costs recoverable through rate adjustments	Up to 12 months	**3,983**	---
Conservation activities (a)	Up to 28 months	**3,589**	3,935
Long-term debt refinancing costs (a)	Up to 25 years	**1,290**	1,017
Other (a)	Up to 50 years	**457**	763
Total regulatory assets		**144,815**	164,943
Regulatory liabilities:			
Plant removal costs (b)		**185,793**	177,655
Deferred income taxes**		**25,325**	32,125
Natural gas costs refundable through rate adjustments		**16,874**	35,262
Taxes refundable to customers (b)		**9,109**	11,769
Other (b)		**8,460**	5,848
Total regulatory liabilities		**245,561**	262,659
Net regulatory position		**$ (100,746)**	$ (97,716)

* *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 - other on the Consolidated Balance Sheets.

(b) Included in other regulatory liabilities - noncurrent on the Consolidated Balance Sheets.

(c) 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, 2013 and 2012, approximately $68.8 million and $91.5 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 – 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 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 $2.9 million and $2.3 million as of December 31, 2013 and 2012, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2013 and 2012, were $624,000 and $240,000, respectively. 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 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, 2013 and 2012, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2013, 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, 2013
		(In thousands)		
Assets:				
Money market funds	$ ---	$ 565	$ ---	$ 565
Insurance contract*	---	2,888	---	2,888
Total assets measured at fair value	$ ---	$ 3,453	$ ---	$ 3,453

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

	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
Insurance contract*	---	2,264	---	2,264
Total assets measured at fair value	$ ---	$ 3,382	$ ---	$ 3,382

** The insurance 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 investments.*

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:

	2013		2012	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$ 409,227**	**$ 419,506**	$ 335,727	$ 381,122

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

NOTE 5 – 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. 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 revolving credit facilities of the Company and its subsidiaries:

Company	Facility	Facility Limit	Amount Outstanding at December 31, 2013	Amount Outstanding at December 31, 2012	Letters of Credit at December 31, 2013	Expiration Date
			(Dollars in millions)			
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (a)	$ 11.5	$ 2.0	$ 2.2 (b)	7/9/18
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (c)	$ 3.0	$ 26.2	$ ----	7/13/18

(a) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(b) The outstanding letter of credit, as discussed on Note 10, reduces the amount available under the credit agreement.
(c) Certain provisions allow for increased borrowings, up to a maximum of $90 million.

The following includes information related to the preceding table.

Short-term borrowings

Cascade Natural Gas Corporation On July 9, 2013, Cascade entered into a revolving credit agreement which replaced the previous revolving credit agreement and extended the termination date to July 9, 2018. Any borrowings under the revolving credit agreement would be classified as short-term borrowings as Cascade intends to repay the borrowings within one year. The weighted average interest rate for borrowings outstanding at December 31, 2013, was 3.3 percent.

The 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. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

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 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).

On December 12, 2013, the Company entered into a note purchase agreement. The Company contracted to issue $30.0 million of Senior Notes under the agreement on January 27, 2014, with due dates ranging from January 2029 to January 2044 at a weighted average interest rate of 5.3 percent. The note purchase agreement contains customary covenants and provisions which are no more restrictive than the covenants described above for the master shelf agreement.

Intermountain Gas Company On July 15, 2013, Intermountain entered into a revolving credit agreement which replaced the previous revolving credit agreement and extended the termination date to July 13, 2018. These borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings. The borrowings outstanding as of December 31, 2012, were classified as short-term borrowings because the previous revolving credit agreement expired within one year.

The credit agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Intermountain's credit agreement also contains cross-default provisions. These provisions state that if Intermountain 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, or certain conditions result in an early termination date under any swap contract that is in excess of a specified amount, then Intermountain will be in default under the revolving credit agreement.

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

	2013	2012
	(In thousands)	
Senior Notes at a weighted average rate of 5.21%, due on dates ranging from October 1, 2015 to January 27, 2044	**$ 331,364**	$ 236,637
Medium-Term Notes, at a weighted average rate of 7.32% due on dates ranging from September 15, 2027 to March 16, 2029	**35,000**	59,000
Credit agreement at a rate of 3.25% due July 13, 2018	**3,000**	---
Other notes, at a weighted average rate of 5.23% due on dates ranging from September 1, 2020 to February 1, 2035	**39,863**	40,090
Total long-term debt	**409,227**	335,727
Less current maturities	**5,273**	59,273
Net long-term debt	**$ 403,954**	$ 276,454

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2013, aggregate $5.3 million in 2014; $55.3 million in 2015; $5.3 million in 2016; $40.2 million in 2017; $8.3 million in 2018 and $294.8 million thereafter.

NOTE 6 – 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 regulatory liabilities-noncurrent, for the years ended December 31 was as follows:

	2013	2012
	(In thousands)	
Balance at beginning of year	**$547**	$493
Accretion expense	**23**	54
Balance at end of year	**$570**	$547

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.

NOTE 7 – INCOME TAXES

Income before income taxes for the years ended December 31, 2013 and 2012 was $37,849 and $27,872, respectively.

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

	2013	2012
	(In thousands)	
Current:		
Federal	**$ 1,420**	$ (5,261)
State	**(918)**	(264)
	502	(5,525)
Deferred:		
Income taxes –		
Federal	**12,096**	13,663
State	**318**	906
Investment tax credit	**(159)**	101
	12,255	14,670
Change in accrued interest	**39**	37
Total income tax expense	**$ 12,796**	$ 9,182

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

	2013	2012
	(In thousands)	
Deferred tax assets:		
Regulatory matters	**$ 75,476**	$ 72,951
Contingency reserve	**4,829**	5,315
Accrued pension costs	**13,675**	21,651
Other	**5,441**	3,483
Total deferred tax assets	**99,421**	103,400
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**203,762**	188,836
Regulatory matters	**25,325**	32,125
Other	**629**	144
Total deferred tax liabilities	**229,716**	221,105
Net deferred income tax liability	**$ (130,295)**	$ (117,705)

As of December 31, 2013 and 2012, 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, 2012, to December 31, 2013, to deferred income tax expense:

	2013
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 12,590**
Regulatory matters	**(335)**
Deferred income tax expense for the period	**$ 12,255**

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,	**2013**		2012	
	Amount	%	Amount	%
	(Dollars in thousands)			
Computed tax at federal statutory rate	**$ 13,247**	**35.0**	$ 9,756	35.0
Increases (reductions) resulting from:				
State income taxes, net of federal income tax	**493**	**1.3**	158	0.6
Amortization and deferral of investment tax credit	**241**	**0.6**	53	0.2
Resolution of tax matters and uncertain tax positions	**(978)**	**(2.6)**	31	0.1
Flow-through	**(84)**	**(0.2)**	(93)	(0.4)
AFUDC equity	**---**	**---**	(416)	(1.5)
Other	**(123)**	**(0.3)**	(307)	(1.1)
Total income tax expense	**$ 12,796**	**33.8**	$ 9,182	32.9

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.

The amount of unrecognized tax benefits (excluding interest) for the years ended December 31, 2013 and 2012 remained unchanged at $2.6 million. For the year ended December 31, 2013, additions for tax positions of prior years of $1.0 million were recognized and settled related to Idaho state audit adjustments.

Included in the balance of unrecognized tax benefits at December 31, 2013 and 2012, 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 $1.8 million, including approximately $343,000 for the payment of interest and penalties at December 31, 2013, and was $1.7 million, including approximately $296,000 for the payment of interest and penalties at December 31, 2012.

It is likely that substantially all of the unrecognized tax benefits, as well as interest, at December 31, 2013, will be settled in the next twelve months due to the anticipated settlement of federal and state audits.

For the years ended December 31, 2013 and 2012, the Company recognized approximately $77,000 and $45,000, respectively, in interest expense and no penalties related to unrecognized tax benefits. The Company recognized interest income of approximately $152,000 and $12,000 for the years ended December 31, 2013 and 2012, respectively. The Company had accrued liabilities of approximately $477,000 and $257,000 at December 31, 2013 and 2012, respectively, for the payment of interest.

In September 2013, the Internal Revenue Service released final regulations relating to the capitalization of tangible personal property which are effective for tax years beginning on or after January 1, 2014. The Company does not expect these new regulations to have a material effect on its results of operations, financial position or cash flows.

NOTE 8 – 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, 2013 and 2012 and amounts recognized in the Consolidated Balance Sheets at December 31, 2013 and 2012, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	**2013**	2012
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 92,987**	$ 87,104	**$ 23,834**	$ 25,345
Service cost	**---**	939	**221**	197
Interest cost	**3,297**	3,473	**743**	912
Plan participants' contributions	**---**	---	**440**	458
Actuarial (gain) loss	**(10,090)**	5,618	**(4,513)**	(1,250)
Benefits paid	**(4,266)**	(4,147)	**(1,802)**	(1,828)
Benefit obligation at end of year	**81,928**	92,987	**18,923**	23,834
Change in net plan assets:				
Fair value of plan assets at beginning of year	**62,714**	55,011	**17,780**	17,079
Actual gain on plan assets	**7,339**	6,901	**3,318**	1,660
Employer contribution	**3,200**	4,949	**722**	411
Plan participants' contributions	**---**	---	**440**	458
Benefits paid	**(4,266)**	(4,147)	**(1,802)**	(1,828)
Fair value of net plan assets at end of year	**68,987**	62,714	**20,458**	17,780
Funded status – over (under)	**$ (12,941)**	$ (30,273)	**$ 1,535**	$ (6,054)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (liabilities) (noncurrent)	**$ (12,941)**	$ (30,273)	**$ 1,535**	$ (6,054)
Net amount recognized	**$ (12,941)**	$ (30,273)	**$ 1,535**	$ (6,054)
Amounts recognized in regulatory assets (liabilities) consist of:				
Actuarial loss	**$ 30,647**	$ 45,408	**$ 4,629**	$ 12,340
Prior service cost (credit)	**---**	---	**(2,196)**	(2,438)
Total	**$ 30,647**	$ 45,408	**$ 2,433**	$ 9,902

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 pension plan has accumulated benefit obligations in excess of plan assets. The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for these plans at December 31 were as follows:

	2013	2012
	(In thousands)	
Projected benefit obligation	**$ 81,928**	$92,987
Accumulated benefit obligation	**$ 81,928**	$92,987
Fair value of plan assets	**$ 68,987**	$62,714

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	
	2013	2012	**2013**	2012
		(In thousands)		
Components of net periodic benefit cost (credit):				
Service cost	**$ ---**	$ 939	**$ 221**	$ 197
Interest cost	**3,297**	3,473	**743**	912
Expected return on assets	**(4,072)**	(4,602)	**(1,026)**	(1,101)
Amortization of prior service credit	**---**	(117)	**(242)**	(713)
Curtailment gain	**---**	(1,023)	**---**	---
Recognized net actuarial loss	**1,404**	2,926	**906**	1,103
Net periodic benefit cost	**629**	1,596	**602**	398
Other changes in plan assets and benefit obligations recognized in regulatory assets (liabilities):				
Net (gain) loss	**(13,357)**	3,320	**(6,805)**	(1,809)
Amortization of actuarial loss	**(1,404)**	(2,926)	**(906)**	(1,103)
Amortization of prior service credit	**---**	1,140	**242**	713
Total recognized in regulatory assets (liabilities)	**(14,761)**	1,534	**(7,469)**	(2,199)
Total recognized in net periodic benefit cost and regulatory assets (liabilities)	**$ 14,132**	$ 3,130	**$ 6,867**	$ (1,801)

The estimated net loss for the defined benefit pension plans that will be amortized from regulatory assets (liabilities) into net periodic benefit cost in 2014 is $1.0 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from regulatory assets (liabilities) into net periodic benefit cost in 2014 are $455,000 and $178,000, respectively. Prior service cost is amortized on a straight line basis over the average remaining service period of active participants.

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

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	**2013**	2012
Discount rate	**4.56%**	3.68%	**4.49%**	3.65%
Expected return on plan assets	**7.00%**	7.00%	**6.00%**	6.00%

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

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	**2013**	2012
Discount rate	**3.68%**	3.62%	**3.65%**	4.12%
Expected return on plan assets	**7.00%**	7.75%	**6.00%**	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 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:

	2013	2012
Health care trend rate assumed for next year	**7.0%**	7.5%
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, 2013:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 54	$ (47)
Effect on postretirement benefit obligation	$ 1,336	$ (1,164)

The Company's pension assets are managed by 16 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 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, 2013 and 2012, there were no transfers between Levels 1 and 2.

The fair value of the Company's pension plan assets (excluding cash) by class were as follows:

	Fair Value Measurements at December 31, 2013, 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, 2013
		(In thousands)		
Assets:				
Cash equivalents	$ 525	$ 1,938	$ ---	$ 2,463
Equity securities:				
U.S. companies	12,897	---	---	12,897
International companies	8,125	---	---	8,125
Collective and mutual funds*	23,954	8,752	---	32,706
Corporate bonds	---	8,802		8,802
Municipal bonds	---	1,558	---	1,558
U.S. Treasury securities	1,543	893	---	2,436
Total assets measured at fair value	$ 47,044	$ 21,943	$ ---	$ 68,987

* *Collective and mutual funds invest approximately 11 percent in common stock of mid-cap U.S. companies, 34 percent in common stock of large-cap U.S. companies, 11 percent in U.S. Treasuries, 27 percent in corporate bonds and 17 percent in other investments.*

The fair value of the Company's pension plan assets by class were 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.*

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

The estimated fair value of the other postretirement benefit plans' 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 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 other postretirement benefit plans' Level 2 insurance 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, 2013 and 2012, there were no transfers between Levels 1 and 2.

The fair value of the Company's other postretirement benefit plans' assets (excluding cash) by asset class were as follows:

	Fair Value Measurements at December 31, 2013, 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, 2013
			(In thousands)	
Assets:				
Cash equivalents	$ 229	$ 336	$ ---	$ 565
Equity securities:				
U.S. companies	1,406	---	---	1,406
International companies	221	---	---	221
Insurance contract*	---	18,266	---	18,266
Total assets measured at fair value	$ 1,856	$ 18,602	$ ---	$ 20,458

** The insurance contract invests approximately 55 percent in common stock of large-cap U.S. companies, 12 percent in U.S. Treasuries, 8 percent in mortgage-backed securities, 8 percent in common stock of mid-cap U.S. companies, 9 percent in corporate bonds, and 8 percent in other investments.*

The fair value of the Company's other postretirement benefit plans' assets by asset class were 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 contract*	---	15,429	---	15,429
Total assets measured at fair value	$ 1,876	$ 15,904	$ ---	$ 17,780

** The insurance 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.*

The Company expects to contribute approximately $5.6 million to its defined benefit pension plan and approximately $613,000 to its postretirement benefit plans in 2014.

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)	
2014	$ 4,416	$ 1,378	$ 5
2015	4,481	1,386	4
2016	4,564	1,400	4
2017	4,663	1,359	3
2018	4,845	1,300	3
2019-2023	25,755	6,142	9

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's net periodic benefit cost for these plans was $1.2 million for both 2013 and 2012. The total projected benefit obligation for these plans was $14.0 million and $15.6 million at December 31, 2013 and 2012, respectively. The accumulated benefit obligations for these plans were $13.9 million and $15.6 million at December 31, 2013 and 2012, respectively. A weighted average discount rate of 4.3 percent and 3.4 percent at December 31, 2013 and 2012, respectively, and a rate of compensation increase of 4.0 percent at both December 31, 2013 and December 31, 2012, were used to determine benefit obligations. A discount rate of 3.4 percent and 3.9 percent at December 31, 2013 and 2012, respectively, and a rate of compensation increase of 3.0 percent and 4.0 percent at December 31, 2013 and 2012, respectively, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $927,000 in 2014; $921,000 in 2015; $1.0 million in 2016; $1.0 million in 2017; $1.1 million in 2018; and $5.0 million for the years 2019 through 2023.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Costs incurred under this plan for 2013 and 2012 were $19,000 and $18,000 respectively.

The Company had investments of $10.1 million and $9.7 million at December 31, 2013 and 2012, respectively, consisting of equity securities of $2.5 million and $1.9 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $6.7 million and $6.4 million, respectively, and other investments of $934,000 and $1.4 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans.

Defined contribution plans
The Company sponsors various defined contribution plans for eligible employees and the costs incurred by the Company under these plans were $3.6 million in 2013 and $1.6 million in 2012.

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 2013 and 2012 is for the plan's year-end at December 31, 2012, and December 31, 2011, 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 2013	Pension Protection Act Zone Status 2012	FIP/RP Status Pending/ Implemented	Contributions **2013**	Contributions 2012	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)			
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2013	Green as of 5/31/2012	No	**$ 1,121**	$ 1,085	No	05/31/2014

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, 2012 and 2011, respectively.

NOTE 9 – REGULATORY MATTERS

On December 31, 2012, the WUTC issued a policy statement for the accelerated replacement of natural gas pipeline facilities with elevated risk. On May 31, 2013, Cascade filed a pipeline replacement cost recovery mechanism with rate changes to coincide with its PGA. The WUTC approved recovery of $1.0 million of qualified pipeline replacement projects to be recovered from November 1, 2013 to October 31, 2014.

On March 13, 2013, the OPUC approved an extension of Cascade’s decoupling mechanism until December 31, 2015. As part of the decoupling mechanism extension, Cascade agreed to file a rate case no later than March 31, 2015. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

NOTE 10 – COMMITMENTS AND CONTINGENCIES

Claims and Litigation

The Company is subject to claims and lawsuits arising out of its business. 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, in some circumstances, an estimate of the possible loss. The Company had accrued liabilities of $14.0 million and $14.5 million for contingencies including litigation and environmental matters as of December 31, 2013 and 2012, respectively, which includes amounts that may have been accrued for matters discussed in Environmental matters within this note.

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. In January 2013, the OPUC approved Cascade's application to defer environmental remediation costs at the Eugene site for a period of 12 months starting November 30, 2012. Cascade received an order reauthorizing the deferred accounting for the 12 months starting November 30, 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 of Superfund sites. Cascade has entered into an administrative settlement agreement and consent order with the EPA regarding the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $12.0 million for the remedial investigation, feasibility study and 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 and entered into agreements with 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. In 2013, Cascade received insurance payments of $952,000 for the Eugene defense costs. 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, 2013, were $881,000 in 2014, $294,000 in 2015, $203,000 in 2016, $147,000 in 2017, $116,000 in 2018, and $308,000 thereafter. Rent expense was $402,000 and $353,000 for the years ended December 31, 2013 and 2012, respectively.

Purchase commitments
The Company has entered into various commitments, largely natural gas supply and natural gas transportation and storage contracts, some of which are subject to variability in volume and price. These commitments range from one to 47 years. The commitments under these contracts as of December 31, 2013, were $273.6 million in 2014, $194.9 million in 2015, $109.6 million in 2016, $74.2 million in 2017, $57.6 million in 2018, and $844.0 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, 2013 and 2012, respectively, were approximately $248.6 million and $253.8 million.

Guarantees
Cascade has an outstanding letter of credit to a third party related to a remedial investigation feasibility study. At December 31, 2013, the fixed maximum amount guaranteed under this letter of credit was $2.2 million, which is scheduled to expire in 2014. There were no amounts outstanding under this letter of credit at December 31, 2013.

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 $27.6 million and $32.3 million for the years ended December 31, 2013 and 2012, respectively and the amount charged for services received from the Company was $360,000 and $332,000 for the years ended December 31, 2013 and 2012, respectively.

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

	2013	2012
	(In thousands)	
Accounts receivable	**$ 108**	$ 69
Accounts payable	**2,341**	2,429
Dividend payable	**5,300**	---

MDU has several stock-based compensation plans in which the Company participates. Total stock-based compensation expense for the years ended December 31, 2013 and 2012, respectively, was $654,000 and

$644,000, net of income taxes of $418,000 and $412,000, respectively. As of December 31, 2013, total remaining unrecognized compensation expense related to stock-based compensation was approximately $1.2 million (before income taxes) which will be amortized over a weighted average period of 1.7 years.

NOTE 12 – SUBSEQUENT EVENT

On December 12, 2013, the Company entered into a note purchase agreement. The Company issued $30.0 million of Senior Notes under the agreement on January 27, 2014, with due dates ranging from January 2029 to January 2044 at a weighted average interest rate of 5.3 percent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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)	760,961,390
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	6,996,150
7	Experimental Plant Unclassified	
8	TOTAL Utility Plant (Total of lines 3 thru 7)	767,957,540
9	Leased to Others	
10	Held for Future Use	
11	Construction Work in Progress	12,554,927
12	Acquisition Adjustments	
13	TOTAL Utility Plant (Total of lines 8 thru 12)	780,512,467
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	385,942,905
15	Net Utility Plant (Total of lines 13 and 14)	394,569,562
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	(382,583,084)
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	(3,359,821)
22	TOTAL In Service (Total of lines 18 thru 21)	(385,942,905)
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 Adjustment	
33	TOTAL Accum. Provisions (Should agree with line 14 above)(Total of lines 22, 26, 30, 31, and 32)	(385,942,905)

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		760,961,390		
4				
5				
6		6,996,150		
7				
8		767,957,540		
9				
10				
11		12,554,927		
12				
13		780,512,467		
14		385,942,905		
15		394,569,562		
16				
17				
18		(382,583,084)		
19				
20				
21		(3,359,821)		
22		(385,942,905)		
23				
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31				
32				
33		(385,942,905)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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	
3	302 Franchises and Consents	211,825	
4	303 Miscellaneous Intangible Plant	16,994,664	5,888,997
5	TOTAL Intangible Plant (Enter Total of lines 2 thru 4)	17,358,555	5,888,997
6	PRODUCTION PLANT		
7	Natural Gas Production and 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 Equipment		
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 and Development Costs		
26	339 Asset Retirement Costs for Natural Gas Production and		
27	TOTAL Production and Gathering Plant (Enter Total of lines 8		
28	PRODUCTS EXTRACTION PLANT		
29	340 Land and Land Rights		
30	341 Structures and Improvements		
31	342 Extraction and Refining Equipment		
32	343 Pipe Lines		
33	344 Extracted Products Storage Equipment		

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				152,066
3				211,825
4				22,883,661
5				23,247,552
6				
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8				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Gas Plant in Service (Accounts 101, 102, 103, and 106) (continued)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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				
35				
36				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Gas Plant in Service (Accounts 101, 102, 103, and 106) (continued)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
81	TOTAL Nat'l Gas Storage and Processing Plant (Total of lines 57,		
82	TRANSMISSION PLAN		
83	365.1 Land and Land Rights	224,536	
84	365.2 Rights-of-Way	1,026,089	
85	366 Structures and Improvements		
86	367 Mains	15,799,462	4,812
87	368 Compressor Station Equipment		
88	369 Measuring and Regulating Station Equipment	205,099	
89	370 Communication Equipment		
90	371 Other Equipment		
91	372 Asset Retirement Costs for Transmission Plant		
92	TOTAL Transmission Plant (Enter Totals of lines 83 thru 91)	17,255,186	4,812
93	DISTRIBUTION PLANT		
94	374 Land and Land Rights	2,490,246	19,389
95	375 Structures and Improvements	1,420,458	38,330
96	376 Mains	349,074,241	12,748,637
97	377 Compressor Station Equipment	2,000,731	
98	378 Measuring and Regulating Station Equipment-General	20,017,134	1,499,769
99	379 Measuring and Regulating Station Equipment-City Gate		
100	380 Services	181,372,758	8,054,769
101	381 Meters	47,119,672	1,286,018
102	382 Meter Installations	29,719,151	322,306
103	383 House Regulators	9,744,858	355,967
104	384 House Regulator Installations		
105	385 Industrial Measuring and Regulating Station Equipment	7,749,047	1,152,806
106	386 Other Property on Customers' Premises		
107	387 Other Equipment		
108	388 Asset Retirement Costs for Distribution Plant	45,332	3,630
109	TOTAL Distribution Plant (Enter Total of lines 94 thru 108)	650,753,628	25,481,621
110	GENERAL PLANT		
111	389 Land and Land Rights	2,253,273	
112	390 Structures and Improvements	17,068,565	428,996
113	391 Office Furniture and Equipment	9,727,355	1,163,412
114	392 Transportation Equipment	10,599,309	2,202,278
115	393 Stores Equipment	69,362	
116	394 Tools, Shop, and Garage Equipment	5,275,529	588,311
117	395 Laboratory Equipment	138,043	
118	396 Power Operated Equipment	2,369,703	1,882,450
119	397 Communication Equipment	4,396,952	915,982
120	398 Miscellaneous Equipment	57,722	
121	Subtotal (Enter Total of lines 111 thru 120)	51,955,813	7,181,429
122	399 Other Tangible Property		
123	399.1 Asset Retirement Costs for General Plant		
124	TOTAL General Plant (Enter Total of lines 121, 122 and 123)	51,955,813	7,181,429
125	TOTAL (Accounts 101 and 106)	737,323,182	38,556,859
126	Gas Plant Purchased (See Instruction 8)		
127	(Less) Gas Plant Sold (See Instruction 8)		
128	Experimental Gas Plant Unclassified		
129	TOTAL Gas Plant In Service (Enter Total of lines 125 thru 128)	737,323,182	38,556,859

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

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				
82				
83				224,536
84				1,026,089
85				
86				15,804,274
87				
88	6,985			198,114
89				
90				
91				
92	6,985			17,253,013
93				
94				2,509,635
95				1,458,788
96	488,317			361,334,561
97				2,000,731
98	48,242			21,468,661
99				
100	382,333			189,045,194
101	439,077	(1,386)		47,965,227
102	13,205	1,386		30,029,638
103	177,986			9,922,839
104				
105	11,431			8,890,422
106				
107				
108				48,962
109	1,560,591			674,674,658
110				
111				2,253,273
112				17,497,561
113	3,735,246			7,155,521
114	1,106,772			11,694,815
115	13,586			55,776
116	64,327			5,799,513
117				138,043
118	1,335,590			2,916,563
119	80,563			5,232,371
120	18,841			38,881
121	6,354,925			52,782,317
122				
123				
124	6,354,925			52,782,317
125	7,922,501			767,957,540
126				
127				
128				
129	7,922,501			767,957,540

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, describe 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				
8				
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45	**Total**			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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			
2				
3				
4				
5				
6				
7				
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9				
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44				
45	**Total**			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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				
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45	**Total**			

Construction Work in Progress-Gas (Account 107)

1. Report below descriptions and balances at end of year of projects 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 Account 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	MN - Hanford/DOE Transmission Main	3,357,903	
2	GIS Compliance Improvements	2,159,322	
3	Replace 12" HP Main in Kelso	1,392,716	
4	Belfair 4" Main Relocation	1,306,397	
5			
6			
7			
8	Minor distribution system/general Plant projects each under		
9	$1 million	4,338,589	
10			
11			
12			
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45	**Total**	**12,554,927**	

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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	Total			0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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							
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General Description of Construction Overhead Procedure

1. For each construction overhead explain: (a) the nature and extent of work, etc., 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 specific project, along with the associated payroll taxes and employee benefit costs.

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 Fixed Assets Analyst and approved by the Manager of General & Asset Accounting which is then applied to the current month activity for all applicable work orders to determine how much should be transferred from the ES/GA pools to the affected work orders. This is accomplished via a system (PowerPant) batch operation. An applicable work order is one that 1) is capital installation/purchase, and not a preliminary survey or investigative in nature. Note that purchase projects only receive GA overhead, not ES. Construction projects receive both.

2. ALLOWANCE FOR BORROWED FUNDS USED DURING CONSTRUCTION (AFUDC):

The formula on page 218a is used.

General Description of Construction Overhead Procedure (continued)

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

1. For line (5), column (d) below, enter the rate granted in the last rate proceeding. If not available, use the average rate earned during the preceding 3 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 Ration (percent) (c)	Cost Rate Percentage (d)
	(1) Average Short-Term Debt	S 16,740,510		
	(2) Short-Term Interest			s 2.34
	(3) Long-Term Debt	D 136,145,572	45.10	d 6.80
	(4) Preferred Stock	P		p
	(5) Common Equity	C 165,989,164	54.90	c 10.00
	(6) Total Capitalization	302,134,736	100.00	
	(7) Average Construction Work In Progress Balance	W 14,944,115		

2. Gross Rate for Borrowed Funds s(S/W) + d[(D/(D+P+C)) (1-(S/W))] 2.34

3. Rate for Other Funds [1-(S/W)] [p(P/(D+P+C)) + c(C/(D+P+C))]

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 2.34

b. Rate for Other Funds -

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Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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, page 204-209, column (d), excluding retirements of nondepreciable 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 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.
5. At lines 7 and 14, add rows as necessary to report all data. Additional rows should be numbered in sequence, e.g., 7.01, 7.02, etc.

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	(370,805,535)	(370,805,535)		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	(19,158,714)	(19,158,714)		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Expense of Gas Plant Leased to Others				
6	Transportation Expenses - Clearing	(972,006)	(972,006)		
7	Other Clearing Accounts				
8	Other Clearing (Specify) (footnote details):	(24,938)	(24,938)		
9					
10	TOTAL Deprec. Prov. for Year (Total of lines 3 thru 8)	(20,155,658)	(20,155,658)		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	7,922,501	7,922,501		
13	Cost of Removal	1,041,881	1,041,881		
14	Salvage (Credit)	1,111,807	1,111,807		
15	TOTAL Net Chrgs for Plant Ret. (Total of lines 12 thru 14)	7,852,575	7,852,575		
16	Other Debit or Credit Items (Describe) (footnote details):	525,534	525,534		
17					
18	Book Cost of Asset Retirement Costs				
19	Balance End of Year (Total of lines 1,10,15,16 and 18)	(382,583,084)	(382,583,084)		
	Section B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS				
21	Productions-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 Terminaling and Processing Plant				
27	Transmission	(10,649,159)	(10,649,159)		
28	Distribution	(347,101,908)	(347,101,908)		
29	General	(24,832,017)	(24,832,017)		
30	TOTAL (Total of lines 21 thru 29)	(382,583,084)	(382,583,084)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Gas Stored (Accounts 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 to 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)	(Account 117.1) (b)	(Account 117.2) (c)	Noncurrent (Account 117.3) (d)	(Account 117.4) (e)	Current (Account 164.1) (f)	LNG (Account 164.2) (g)	LNG (Account 164.3) (h)	Total (i)
1	Balance at Beginning of						3,166,527		3,166,527
2	Gas Delivered to Storage						373,045		373,045
3	Gas Withdrawn from						646,098		646,098
4	Other Debits and Credits					960,973			960,973
5	Balance at End of Year					960,973	2,893,474		3,854,447
6	Dth					243,485	535,886		779,371
7	Amount Per Dth					3.9467	5.3994		4.9456

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 reacquired 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) Investment 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 difference) (c)	Purchases or Additions During the Year (d)
1				
2	Account 124			
3	Oregon weatherization loans			
4	Customer Note Receivable			
5	SERP Plan Assets		9,722,357	904,600
6	SISP Plan Assets		17,548	21,912
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)			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 footnote 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 footnote and explain difference) (g)	Revenues for Year (h)	Gain or Loss from Investment Disposed of (i)
1					
2					
3					
4					
5	570,848		10,056,109	904,600	
6			39,460	3,312	
7					
8					
9					
10					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Investments in Subsidiary Companies (Account 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				
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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/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Investments in Subsidiary Companies (Account 123.1) (continued)

4. Designate in a footnote, any securities, notes, or accounts that were pledged, and state the name of pledgee 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 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 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				
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Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and Regulatory Study Costs (Acct 182.2)

PREPAYMENTS (ACCOUNT 165)

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

Line No.	Nature of Payment (a)	Balance at End of Year (in dollars) (b)
1	Prepaid Insurance	108,161
2	Prepaid Rents	3,936,424
3	Prepaid Taxes	655,994
4	Prepaid Interest	
5	Miscellaneous Prepayments	50,150
6	TOTAL	4,750,729

Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and 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 (Mo, Da, Yr)	Year/Period of Report
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Prepayments (Acct 165), Extraordinary Property Losses (Acct 182.1), Unrecovered Plant and 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 description 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 for extraordinary property losses. (a)	Balance at Beginning of Year (b)	Total Amount of Charges (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) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

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 citation where authorization 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 Quarter/Year (b)	Debits (c)	Written off During Quarter/Year Account Charged (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	Miscellaneous						
3							
4							
5	OR Tax Rate Change	(426,152)	23,675	various			(402,477)
6							
7	Asset Retirement Obligation	473,089	65,947				539,036
8	(WA regulatory asset)						
9							
10	Asset Retirement Obligation	43,790	(22,168)				21,622
11	(OR regulatory asset)						
12							
13	SFAS 109 Regulatory Asset	432,911	(271,368)	various			161,543
14	(OR regulatory asset)						
15							
16	FAS 158 Regulatory Asset	55,377,267	(19,644,844)				35,732,423
17	(Total system asset)						
18							
19							
20							
21							
22							
23							
24							
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37							
38							
39							
40	**Total**	55,900,905	(19,848,758)	[redacted]	0	0	36,052,147

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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	3,907,595	6,253,910	4800-4813	6,605,957	3,555,548
2	(amortization period 11/10-present)					
3						
4	WA Bremerton Manufactured Gas Plant	13,976,970	583,051		488,420	14,071,601
5	Remediation					
6						
7	WA Gas Management Sharing Margin	179,399	3,063	4800-4813	288,946	(106,484)
8	(amortization period 11/10-present)			4890		
9						
10	WA Over-refunded Temporary Revenue	63,730	13,980		80,718	(3,008)
11	Credit					
12						
13	OR Conservation Programs	(8,142)	2,285,832	4800-4813	4,365,838	(2,088,148)
14	(amortization period 11/10-present)			4890		
15						
16	OR Eugene Manufactured Gas Plant	1,397,053	53,682		87,860	1,362,875
17	Remediation					
18						
19	OR Intervenor Funding	35,785	42,232	4800-4813	42,637	35,380
20	(amortization period 11/10-present)			4890		
21						
22	OR Over-refunded Temporary Revenue	3,342	302		569	3,075
23	Credit					
24						
25	I/C Asset - Net Benefit Funds	1,617,016	345,082			1,962,098
26						
27	Post Retirement FAS 158		1,020,693			1,020,693
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39	Miscellaneous Work in Progress					
40	**Total**	21,172,748	10,601,827		11,960,945	19,813,630

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[Next page is 234]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 included 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	27,838,248	1,652,969	
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	27,838,248	1,652,969	
6	Other (Specify) (footnote details)			
7	TOTAL Account 190 (Total of lines 5 thru 6)	27,838,248	1,652,969	
8	Classification of TOTAL			
9	Federal Income Tax	26,662,464	1,586,762	
10	State Income Tax	1,175,784	66,207	
11	Local Income Tax			

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					See	(5,258,635)	20,926,644
4					footnote		
5						(5,258,635)	20,926,644
6							
7						(5,258,635)	20,926,644
8							
9						(5,036,530)	20,039,172
10						(222,105)	887,472
11							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Capital Stock (Accounts 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 by 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				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Capital Stock (Accounts 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 Amount (j)
1						
2	1,000	1,000				
3						
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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	Premium on Capital Stock - Common		1,000	117,703,952
3				
4	Represents excess received over $1.00 par value			
5	of common stock			
6				
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40	**Total**		**1,000**	**117,703,952**

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 the 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	None	
2		
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40	**Total**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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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12		
13		
14		
	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	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) X An Original (2) _ A Resubmission	12/31/2013	2013/Q4

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

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 amts held by respondent) (d)
1	Account 224			
2				
3	Other Long Term Debt:			
4	Medium Term Notes	02/04/1993	02/04/2013	
5	Medium Term Notes	02/12/1993	02/12/2013	
6	Medium Term Notes	02/25/1993	02/25/2013	
7	Medium Term Notes	09/15/1997	09/15/2027	20,000,000
8	Medium Term Notes	03/16/1999	03/16/2029	15,000,000
9	Insured Quarterly Notes	02/01/2005	02/01/2035	24,863,000
10	Notes	09/01/2005	09/01/2020	15,000,000
11	Senior Notes	03/08/2007	03/08/2037	40,000,000
12	Senior Notes	08/23/2013	08/23/2025	25,000,000
13	Senior Notes	08/23/2013	08/23/2028	25,000,000
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40	**TOTAL**			164,863,000

Long-Term Debt (Accounts 221, 222, 223, and 224)

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 Bonds (Acct 222) (g)	Held by Respondent Sinking and Other Funds (h)	Redemption Price per $100 at End of Year (i)
1					
2					
3					
4	7.950	108,650			
5	8.010	291,475			
6	7.950	318,000			
7	7.480	1,496,000			
8	7.100	1,064,700			
9	5.250	1,312,500			
10	5.210	781,500			
11	5.790	2,316,000			
12	4.110	179,536			
13	4.360	190,457			
14					
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40		8,058,818			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 7.95%	4,000,000	40,242	02/04/1993	02/04/2013
4	Medium Term Notes 8.01%	10,000,000	100,604	02/12/1993	02/12/2013
5	Medium Term Notes 7.95%	10,000,000	100,604	02/25/1993	02/25/2013
6	Medium Term Notes 7.48%	20,000,000	201,406	09/15/1997	09/15/2027
7	Medium Term Notes 7.10%	15,000,000	151,056	03/16/1999	03/16/2029
8	Insured Quarterly Notes 5.25%	25,090,000	1,947,598	02/01/2005	02/01/2035
9	Notes 5.21%	15,000,000	238,755	09/01/2005	09/01/2020
10	Senior Notes 5.79%	40,000,000	232,781	03/08/2007	03/08/2037
11	Senior Notes 4.11%	25,000,000	150,206	08/23/2013	08/23/2025
12	Senior Notes 4.36%	25,000,000	150,206	08/23/2013	08/23/2028
13	Revolving Credit Agreement		68,090	07/09/2013	07/09/2018
14					
15					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Unamortized Debt Expense, Premium and Discount on Long-Term Debt (Accounts 181, 225, 226)

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				
2				
3	187		187	
4	530		530	
5	708		708	
6	98,742		6,711	92,031
7	81,402		5,036	76,366
8	1,484,572		113,853	1,370,719
9	73,519	32,661		106,180
10	187,825		7,770	180,055
11		150,206	5,216	144,990
12		150,206	4,173	146,033
13		204,041	17,291	186,750
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 transaction, 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	9.875% Debentures					
6	Due 08/01/2013 (1)	03/01/1993	21,677,000	(1,984,012)	26,819	
7						
8						
9	7.50% Notes					
10	Due 11/15/2031 (2)	11/15/2001	39,729,000	(1,229,120)	990,124	949,154
11						
12	See footnote					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Reconciliation of Reported Net Income with Taxable Income for Feder 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 accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
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)	15,667,422
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	See footnote	1,832,813
6		
7		
8	TOTAL	1,832,813
9	Deductions Recorded on Books Not Deducted for Return	
10	See footnote	36,173,952
11		
12		
13	TOTAL	36,173,952
14	Income Recorded on Books Not Included in Return	
15	Interest capitalized adj. (IRS>books)	(11,883)
16		
17		
18	TOTAL	(11,883)
19	Deductions on Return Not Charged Against Book Income	
20	See footnote	(55,318,241)
21		
22		
23		
24		
25		
26	TOTAL	(55,318,241)
27	Federal Tax Net Income	(1,655,937)
28	Show Computation of Tax:	
29	Rate - 35.00%	
30	Estimated Tax Return Federal Income Tax	(579,578)
31	Adjustments:	
32	Difference between 12/31/12 accrual and tax return	99,784
33	Provision for Current Federal Income Tax (see footnote)	(479,794)
34	Oregon State Tax Calculation - (see footnote)	(41,581)
35		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts 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 direct 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		
2	Oregon Accrued	(83,881)	
3	Federal Accrued	(853,124)	
4	Fin 48 - current	1,355,760	
5	Gross Revenue		
6	Washington	426,975	
7	Oregon		
8	Dept of Energy - Oregon		28,212
9	City Franchise & Occupation		
10	Washington	1,280,703	
11	Oregon	603,314	
12	Property		
13	Washington	3,191,953	
14	Oregon		639,429
15	Payroll Taxes	47,928	
16	State Excise - Washington	1,611,386	
17			
18	Miscellaneous		
19			
20			
21			
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	TOTAL	7,581,014	667,641

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts 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 direct 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.	Electric (Account 408.1, 409.1) (i)	Gas (Account 408.1, 409.1) (j)	Other Utility Dept. (Account 408.1, 409.1) (k)	Other Income and Deductions (Account 408.2, 409.2) (l)
1				
2		(41,718)		137
3		(481,297)		1,503
4				
5				
6		411,035		
7		170,330		
8		55,657		
9				
10		8,804,362		
11		2,540,211		
12				
13		2,919,876		2,604
14		1,271,648		
15		1,991,378		
16		8,309,875		
17				
18		67,478		
19				
20				
21				
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38				
39				
TOTAL		26,018,835		4,244

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 taxes 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					
2	(41,581)	(109,635)		(15,827)	
3	(482,902)	(1,152,034)		(183,992)	
4	47,494			1,403,254	
5					
6	411,035	417,663		420,347	
7	170,330	170,330			
8	55,657	54,506			27,061
9					
10	8,804,362	8,283,387		1,801,678	
11	2,540,211	2,340,974		802,551	
12					
13	2,922,480	3,358,158		2,756,275	
14	1,271,648	1,261,152			628,933
15	1,991,378	1,959,560		79,746	
16	8,309,875	7,685,695		2,235,566	
17					
18	67,478	67,478			
19					
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TOTAL	26,067,465	24,337,234		9,299,598	655,994

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 taxes 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					
2					1.52
3				(3,108)	
4				47,494	
5					
6					
7					
8					
9					
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TOTAL				44,386	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Miscellaneous 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	Accrued Paid Time Off Liability	1,596,411
2	Accrued 401K Defined Contributions	926,042
3	Wages Payable	831,177
4	Washington Low Income Assist Liability	758,727
5	Variable Pay Incentive Contribution	747,218
6	Energy Trust of Oregon Liability	635,345
7	Accounts Payable Accrual	554,664
8	Oregon Weatherization Liability	528,204
9	SERP Defined Contributions	483,492
10	Professional Services (bank, accounting, legal)	261,072
11	Other Misc. Current Liabilities (aggregate)	279,639
12		
13		
14		
15		
16		
17		
18		
19		
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45	**Total**	**7,601,991**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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	13,878,157	805.1	46,531,633	28,670,481	(3,982,995)
2	(ammortization period 11/11-present)					
3						
4	OR Deferred Gas Costs	5,946,299	805.1	15,876,985	11,575,136	1,644,450
5	(ammortization period 11/11-present)					
6						
7	OR Earning Sharing Liability	338,178	805.1	331,742	2,039	8,475
8	(ammortization period 11/11-present)					
9						
10	SGL Deposit	193,080	134/228.4	24,135		168,945
11	Customer Unclaimed Credits	2,613	131	3,006	6,100	5,707
12	MDUR Interco NC Payable - FAS 158			954,449	1,682,268	727,819
13	Pension Contribution	30,273,221	various	18,290,783	958,627	12,941,065
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45	**Total**	50,631,548		82,012,733	42,894,651	11,513,466

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric			
3	Gas	(77,797,048)	(5,939,706)	
4	Other (Define) (footnote details)			
5	Total (Enter Total of lines 2 thru 4)	(77,797,048)	(5,939,706)	
6	Other (Specify) (footnote details)			
7	TOTAL Account 282 (Enter Total of lines 5 thr	(77,797,048)	(5,939,706)	
8	Classification of TOTAL			
9	Federal Income Tax	(75,123,911)	(5,606,450)	
10	State Income Tax	(2,673,137)	(333,256)	
11	Local Income Tax			

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 Acct. No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2							
3			182.3	215,298	254	585,361	(84,106,817)
4							
5				215,298		585,361	(84,106,817)
6							
7				215,298		585,361	(84,106,817)
8							
9					254	585,361	(81,315,722)
10			182.3	215,298			(2,791,095)
11							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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			
3	Gas	(31,976,752)	(1,505,837)	
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	(31,976,752)	(1,505,837)	
6	Other (Specify) (footnote details)			
7	TOTAL Account 283 (Total of lines 5 thru	(31,976,752)	(1,505,837)	
8	Classification of TOTAL			
9	Federal Income Tax	(30,235,293)	(1,432,733)	
10	State Income Tax	(1,741,459)	(73,104)	
11	Local Income Tax			

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 Acct. No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2							
3			See	5,286,538			(28,196,051)
4			footnote				
5				5,286,538			(28,196,051)
6							
7				5,286,538			(28,196,051)
8							
9				5,032,036			(26,635,990)
10				254,502			(1,560,061)
11							

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

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 Refunded (d)	Written off During Period Amount Deemed Non-Refundable (e)	Credits (f)	Balance at End of Current Quarter/Year (g)
1	SFAS 109 Regulatory Liability	4,285,393	282	810,175		217,025	3,692,243
2	Oregon Tax Rate Change	(59,333)	282			3,296	(56,037)
3	Regulatory Liability - Post Ret FAS 158		186			1,020,693	1,020,693
4	11/11/12 Consolidated Other Technical Adjustments	757	186	323		10	444
5	11/12 Under-Refunded Temporary Revenue Crdit	3,689	186	6,733			(3,044)
6	11/12 Under-Refunded Temporary Revenue Credit		186	1,357		1	(1,356)
7							
8							
9							
10							
11							
12							
13							
14							
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44							
45	**Total**	4,230,506		818,588	0	1,241,025	4,652,943

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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				
2	481 Commercial and Industrial Sales				
3	482 Other Sales to Public Authorities				
4	483 Sales for Resale				
5	484 Interdepartmental Sales				
6	485 Intracompany Transfers				
7	487 Forfeited Discounts				
8	488 Miscellaneous Service Revenues				
9	489.1 Revenues from Transportation of Gas of Others Through Gathering Facilities				
10	489.2 Revenues from Transportation of Gas of Others Through Transmission Facilities				
11	489.3 Revenues from Transportation of Gas of Others Through Distribution Facilities				
12	489.4 Revenues from Storing Gas of Others				
13	490 Sales of Prod. Ext. from Natural Gas				
14	491 Revenues from Natural Gas Proc. by Others				
15	492 Incidental Gasoline and Oil Sales				
16	493 Rent from Gas Property				
17	494 Interdepartmental Rents				
18	495 Other Gas Revenues				
19	Subtotal:				
20	496 (Less) Provision for Rate Refunds				
21	TOTAL:				

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	254,299,357	252,587,028	254,299,357	252,587,028	30,190,159	28,616,848
2						
3						
4						
5						
6						
7						
8	1,275,841	1,348,971	1,275,841	1,348,971		
9						
10						
11	23,444,372	22,916,355	23,444,372	22,916,355	101,421,986	84,552,419
12						
13						
14						
15						
16	104,591	12,600	104,591	12,600		
17						
18	190,787	123,529	190,787	123,529		
19	279,314,948	276,988,483	279,314,948	276,988,483		
20						
21	279,314,948	276,988,483	279,314,948	276,988,483		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Revenues from Transporation of Gas of Others Through Gathering Facilities (Account 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 Transaction 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 Current Year (d)
1	N/A				
2					
3					
4					
5					
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Revenues from Transporation of Gas of Others Through Gathering Facilities (Account 489.1)

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						
5						
6						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Revenues from Transportation of Gas of Others Through Transmission Facilities (Account 489.2)

1. Report revenues and Dth of gas delivered by Zone of Delivery by Rate Schedule. Total by Zone of Delivery and for all zones. If respondent does not have separate zones, provide totals by rate schedule.
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 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	N/A				
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Revenues from Transportation of Gas of Others Through Transmission Facilities (Account 489.2)

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)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
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Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

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 withdrawal charges, less revenues reflected in columns (b) through (e).

Line No.	Rate Schedule (a)	Revenues for Transition Costs and Take-or-Pay Amount for Current Year (b)	Revenues for Transaction 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	N/A				
2					
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Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report End of 2013/Q4

Revenues from Storing Gas of Others (Account 489.4)

4. Dth of gas withdrawn from storage must not be adjusted 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)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 Electricity, 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 Tariff Provisions, including Penalties Associated with Cash-out Settlements	
10	Revenues from Shipper Supplied Gas	
11	Other revenues (Specify):	
12	Miscellaneous Sales	190,787
13		
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39		
	Total	**190,787**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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	Account 489.1, Revenues from transportation of gas of others through gathering facilities.				
2	Account 489.2, Revenues from transportation of gas of others through transmission facilities.				
3	Account 489.4, Revenues from storing gas of others.				
4	Account 495, Other gas revenues.				
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39					
	Total				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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	0	0
8	751 Production Maps and Records	0	0
9	752 Gas Well Expenses	0	0
10	753 Field Lines Expenses	0	0
11	754 Field Compressor Station Expenses	0	0
12	755 Field Compressor Station Fuel and Power	0	0
13	756 Field Measuring and Regulating Station Expenses	0	0
14	757 Purification Expenses	0	0
15	758 Gas Well Royalties	0	0
16	759 Other Expenses	0	0
17	760 Rents	0	0
18	TOTAL Operation (Total of lines 7 thru 17)	0	0
19	Maintenance		
20	761 Maintenance Supervision and Engineering	0	0
21	762 Maintenance of Structures and Improvements	0	0
22	763 Maintenance of Producing Gas Wells	0	0
23	764 Maintenance of Field Lines	0	0
24	765 Maintenance of Field Compressor Station Equipment	0	0
25	766 Maintenance of Field Measuring and Regulating Station Equipment	0	0
26	767 Maintenance of Purification Equipment	0	0
27	768 Maintenance of Drilling and Cleaning Equipment	0	0
28	769 Maintenance of Other Equipment	0	0
29	TOTAL Maintenance (Total of lines 20 thru 28)	0	0
30	TOTAL Natural Gas Production and Gathering (Total of lines 18 and 29)	0	0

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	0	0
34	771 Operation Labor	0	0
35	772 Gas Shrinkage	0	0
36	773 Fuel	0	0
37	774 Power	0	0
38	775 Materials	0	0
39	776 Operation Supplies and Expenses	0	0
40	777 Gas Processed by Others	0	0
41	778 Royalties on Products Extracted	0	0
42	779 Marketing Expenses	0	0
43	780 Products Purchased for Resale	0	0
44	781 Variation in Products Inventory	0	0
45	(Less) 782 Extracted Products Used by the Utility-Credit	0	0
46	783 Rents	0	0
47	TOTAL Operation (Total of lines 33 thru 46)	0	0
48	Maintenance		
49	784 Maintenance Supervision and Engineering	0	0
50	785 Maintenance of Structures and Improvements	0	0
51	786 Maintenance of Extraction and Refining Equipment	0	0
52	787 Maintenance of Pipe Lines	0	0
53	788 Maintenance of Extracted Products Storage Equipment	0	0
54	789 Maintenance of Compressor Equipment	0	0
55	790 Maintenance of Gas Measuring and Regulating Equipment	0	0
56	791 Maintenance of Other Equipment	0	0
57	TOTAL Maintenance (Total of lines 49 thru 56)	0	0
58	TOTAL Products Extraction (Total of lines 47 and 57)	0	0

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	0	0
62	796 Nonproductive Well Drilling	0	0
63	797 Abandoned Leases	0	0
64	798 Other Exploration	0	0
65	TOTAL Exploration and Development (Total of lines 61 thru 64)	0	0
66	D. Other Gas Supply Expenses		
67	Operation		
68	800 Natural Gas Well Head Purchases	0	0
69	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	0	0
70	801 Natural Gas Field Line Purchases	0	0
71	802 Natural Gas Gasoline Plant Outlet Purchases	0	0
72	803 Natural Gas Transmission Line Purchases	0	0
73	804 Natural Gas City Gate Purchases	176,604,343	157,121,712
74	804.1 Liquefied Natural Gas Purchases	0	0
75	805 Other Gas Purchases	0	0
76	(Less) 805.1 Purchases Gas Cost Adjustments	26,394,383	6,570,310
77	TOTAL Purchased Gas (Total of lines 68 thru 76)	150,209,960	150,551,402
78	806 Exchange Gas	0	0
79	Purchased Gas Expenses		
80	807.1 Well Expense-Purchased Gas	0	0
81	807.2 Operation of Purchased Gas Measuring Stations	0	0
82	807.3 Maintenance of Purchased Gas Measuring Stations	0	0
83	807.4 Purchased Gas Calculations Expenses	0	0
84	807.5 Other Purchased Gas Expenses	0	0
85	TOTAL Purchased Gas Expenses (Total of lines 80 thru 84)	0	0

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	4,182,942	2,498,899
87	(Less) 808.2 Gas Delivered to Storage-Credit	4,048,172	2,923,968
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit	0	0
89	(Less) 809.2 Deliveries of Natural Gas for Processing-Credit	0	0
90	Gas used in Utility Operation-Credit		
91	810 Gas Used for Compressor Station Fuel-Credit	0	0
92	811 Gas Used for Products Extraction-Credit	0	0
93	812 Gas Used for Other Utility Operations-Credit	68,058	76,028
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	68,058	76,028
95	813 Other Gas Supply Expenses	374,039	216,405
96	TOTAL Other Gas Supply Exp. (Total of lines 77,78,85,86 thru 89,94,95)	150,650,711	150,266,710
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, and 96)	150,650,711	150,266,710
98	2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering	0	0
102	815 Maps and Records	0	0
103	816 Wells Expenses	0	0
104	817 Lines Expense	0	0
105	818 Compressor Station Expenses	0	0
106	819 Compressor Station Fuel and Power	0	0
107	820 Measuring and Regulating Station Expenses	0	0
108	821 Purification Expenses	0	0
109	822 Exploration and Development	0	0
110	823 Gas Losses	0	0
111	824 Other Expenses	0	0
112	825 Storage Well Royalties	0	0
113	826 Rents	0	0
114	TOTAL Operation (Total of lines of 101 thru 113)	0	0

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	0	0
117	831 Maintenance of Structures and Improvements	0	0
118	832 Maintenance of Reservoirs and Wells	0	0
119	833 Maintenance of Lines	0	0
120	834 Maintenance of Compressor Station Equipment	0	0
121	835 Maintenance of Measuring and Regulating Station Equipment	0	0
122	836 Maintenance of Purification Equipment	0	0
123	837 Maintenance of Other Equipment	0	0
124	TOTAL Maintenance (Total of lines 116 thru 123)	0	0
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)	0	0
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering	0	0
129	841 Operation Labor and Expenses	0	0
130	842 Rents	0	0
131	842.1 Fuel	0	0
132	842.2 Power	0	0
133	842.3 Gas Losses	0	0
134	TOTAL Operation (Total of lines 128 thru 133)	0	0
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	0	0
137	843.2 Maintenance of Structures	0	0
138	843.3 Maintenance of Gas Holders	0	0
139	843.4 Maintenance of Purification Equipment	0	0
140	843.5 Maintenance of Liquefaction Equipment	0	0
141	843.6 Maintenance of Vaporizing Equipment	0	0
142	843.7 Maintenance of Compressor Equipment	0	0
143	843.8 Maintenance of Measuring and Regulating Equipment	0	0
144	843.9 Maintenance of Other Equipment	0	0
145	TOTAL Maintenance (Total of lines 136 thru 144)	0	0
146	TOTAL Other Storage Expenses (Total of lines 134 and 145)	0	0

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	0	0
150	844.2 LNG Processing Terminal Labor and Expenses	0	0
151	844.3 Liquefaction Processing Labor and Expenses	0	0
152	844.4 Liquefaction Transportation Labor and Expenses	0	0
153	844.5 Measuring and Regulating Labor and Expenses	0	0
154	844.6 Compressor Station Labor and Expenses	0	0
155	844.7 Communication System Expenses	0	0
156	844.8 System Control and Load Dispatching	0	0
157	845.1 Fuel	0	0
158	845.2 Power	0	0
159	845.3 Rents	0	0
160	845.4 Demurrage Charges	0	0
161	(less) 845.5 Wharfage Receipts-Credit	0	0
162	845.6 Processing Liquefied or Vaporized Gas by Others	0	0
163	846.1 Gas Losses	0	0
164	846.2 Other Expenses	0	0
165	TOTAL Operation (Total of lines 149 thru 164)	0	0
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	0	0
168	847.2 Maintenance of Structures and Improvements	0	0
169	847.3 Maintenance of LNG Processing Terminal Equipment	0	0
170	847.4 Maintenance of LNG Transportation Equipment	0	0
171	847.5 Maintenance of Measuring and Regulating Equipment	0	0
172	847.6 Maintenance of Compressor Station Equipment	0	0
173	847.7 Maintenance of Communication Equipment	0	0
174	847.8 Maintenance of Other Equipment	0	0
175	TOTAL Maintenance (Total of lines 167 thru 174)	0	0
176	TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 and 175)	0	0
177	TOTAL Natural Gas Storage (Total of lines 125, 146, and 176)	0	0

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	0	0
181	851 System Control and Load Dispatching	0	0
182	852 Communication System Expenses	0	0
183	853 Compressor Station Labor and Expenses	0	0
184	854 Gas for Compressor Station Fuel	0	0
185	855 Other Fuel and Power for Compressor Stations	0	0
186	856 Mains Expenses	0	0
187	857 Measuring and Regulating Station Expenses	0	0
188	858 Transmission and Compression of Gas by Others	0	0
189	859 Other Expenses	0	0
190	860 Rents	0	0
191	TOTAL Operation (Total of lines 180 thru 190)	0	0
192	Maintenance		
193	861 Maintenance Supervision and Engineering	0	0
194	862 Maintenance of Structures and Improvements	0	0
195	863 Maintenance of Mains	0	0
196	864 Maintenance of Compressor Station Equipment	0	0
197	865 Maintenance of Measuring and Regulating Station Equipment	0	0
198	866 Maintenance of Communication Equipment	0	0
199	867 Maintenance of Other Equipment	0	0
200	TOTAL Maintenance (Total of lines 193 thru 199)	0	0
201	TOTAL Transmission Expenses (Total of lines 191 and 200)	0	0
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	1,781,876	932,760
205	871 Distribution Load Dispatching	504,809	514,554
206	872 Compressor Station Labor and Expenses	113,822	77,125
207	873 Compressor Station Fuel and Power	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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	4,386,187	4,601,898
209	875 Measuring and Regulating Station Expenses-General	776,853	708,003
210	876 Measuring and Regulating Station Expenses-Industrial	165,452	151,563
211	877 Measuring and Regulating Station Expenses-City Gas Check Station	0	0
212	878 Meter and House Regulator Expenses	1,805,503	1,350,743
213	879 Customer Installations Expenses	1,375,909	1,688,999
214	880 Other Expenses	4,475,306	4,261,747
215	881 Rents	105,439	84,695
216	TOTAL Operation (Total of lines 204 thru 215)	15,491,156	14,372,087
217	Maintenance		
218	885 Maintenance Supervision and Engineering	384,799	45,097
219	886 Maintenance of Structures and Improvements	21,689	38,618
220	887 Maintenance of Mains	1,673,148	1,493,162
221	888 Maintenance of Compressor Station Equipment	9,053	18,187
222	889 Maintenance of Measuring and Regulating Station Equipment-General	509,229	488,774
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial	63,985	119,307
224	891 Maintenance of Meas. and Reg. Station Equip-City Gate Check Station	0	0
225	892 Maintenance of Services	1,425,748	1,193,488
226	893 Maintenance of Meters and House Regulators	1,261,481	1,172,517
227	894 Maintenance of Other Equipment	181,641	489,198
228	TOTAL Maintenance (Total of lines 218 thru 227)	5,530,773	5,058,348
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	21,021,929	19,430,435
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	25,965	55,114
233	902 Meter Reading Expenses	686,578	616,701
234	903 Customer Records and Collection Expenses	4,454,512	4,544,898

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
235	904 Uncollectible Accounts	1,040,101	2,480,745
236	905 Miscellaneous Customer Accounts Expenses	9,220	141,820
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	6,216,376	7,839,278
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	1,932,560	1,397,354
242	909 Informational and Instructional Expenses	29,068	108,027
243	910 Miscellaneous Customer Service and Informational Expenses	0	0
244	TOTAL Customer Service and Information Expenses (Total of lines 240 thru 243)	1,961,628	1,505,381
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	0	0
249	913 Advertising Expenses	7,755	10,310
250	916 Miscellaneous Sales Expenses	0	0
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	7,755	10,310
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	6,297,212	6,329,723
255	921 Office Supplies and Expenses	5,056,018	5,155,348
256	(Less) 922 Administrative Expenses Transferred-Credit	540,949	527,933
257	923 Outside Services Employed	768,765	852,593
258	924 Property Insurance	78,247	72,980
259	925 Injuries and Damages	364,683	982,732
260	926 Employee Pensions and Benefits	5,021,331	4,425,621
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	0	646
263	(Less) 929 Duplicate Charges-Credit	0	0
264	930.1General Advertising Expenses	106,011	67,608
265	930.2Miscellaneous General Expenses	687,930	638,635
266	931 Rents	1,304,714	1,336,381
267	TOTAL Operation (Total of lines 254 thru 266)	19,143,962	19,334,334
268	Maintenance		
269	932 Maintenance of General Plant	57,390	56,493
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	19,201,352	19,390,827
271	TOTAL Gas O&M Expenses (Total of lines 97,177,201,229,237,244,251, and 270)	199,059,751	198,442,941

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	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	**Total**	0	0	0	0

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 operating 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	16,892	68,058		
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25	**Total**		16,892	68,058		

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 dollars) (c)	Dth of Gas Delivered (d)
1	None			
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24				
25	**Total**			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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	434,093
2	Vehicle Mileage	245
3	Airfare and related costs	13,109
4	Meals	2,502
5	Lodging	10,930
6	Office Supplies	674
7	Training Meetings and Materials	7,438
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25	**Total**	468,991

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 (c) 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.	136,263
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	Other expenses	
5	Bank and Other Finance Fees (paid to Bank of New York, Payflex, and MDU for CNGC's share of	
6	corporate banking fees)	248,182
7	Director's Fees (paid to MDU for CNGC's share of director's expenses)	298,393
8	Miscellaneous under $250,000 (13 items)	5,092
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25	**Total**	687,930

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Depreciation, Depletion and Amortization of Gas Plant (Accts 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 (Account 404.1) (d)	Amortization of Underground Storage Land and Land Rights (Account 404.2) (e)
1	Intangible plant				1,523,238
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	321,191			
9	Distribution plant	17,740,035			
10	General plant	1,097,488			
11	Common plant-gas				
12	TOTAL	19,158,714			1,523,238

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition Adjustments) (continued)

obtained. If average balances are 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 the 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			1,523,238	Intangible plant
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			321,191	Transmission plant
9			17,740,035	Distribution plant
10			1,097,488	General plant
11				Common plant-gas
12			20,681,952	TOTAL

Depreciation, Depletion and Amortization of Gas Plant (Accts 403, 404.1, 404.2, 404.3, 405) (Except Amortization of Acquisition 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	See footnote		
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11			
12			
13			
14			
15			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 account, (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)	210,111
5	Life Insurance (Account 426.2)	
6	Penalties (Account 426.3)	
7	Expenditures for Certain Civic, Political and Related Activities	113,170
8	(Account 426.4)	
9	Other Deductions (Account 426.5)	
10	Payee Nature	
11	MDU/MDU Resources CNGC share of Corporate Development	40
12	Total Miscellaneous Income Deductions (Account 426)	323,321
13		
14	(c) Interest on Debt to Associated Companies (Account 430)	
15		
16	(d) Other Interest Expense (Account 431)	
17	Description Interest Rate	
18	Customer Deposits Various	2,947
19	Deferral Accounts-WA FERC Interest Rate	191,762
20	Deferral Accounts-OR ***	81,635
21	Interest on Short-Term Debt Various	816,640
22	Other Various	47,926
23	Total Other Interest Expense (Account 431)	1,140,910
24		
25	***Accounts not amortizing - 8.709% (Overall rate of return granted in the last	
26	Oregon general rate filing); Accounts amortizing - 1.38%	
27		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Regulatory Commission Expenses (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 column (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	None				
2					
3					
4					
5					
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24					
25	**Total**				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Regulatory Commission Expenses (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 year which were charges currently to income, plant, or other accounts.
6. Minor items (less than $250,000) may be grouped.

Line No.	Expenses Incurred During Year Charged Currently To Department (f)	Expenses Incurred During Year Charged Currently To Account No. (g)	Expenses Incurred During Year Charged Currently To Amount (h)	Expenses Incurred During Year Deferred to Account 182.3 (i)	Amortized During Year Contra Account (j)	Amortized During Year Amount (k)	Deferred in Account 182.3 End of Year (l)
1							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

Employee Pensions and Benefits (Account 926)

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

Line No.	Expense (a)	Amount (b)
1	Pensions – defined benefit plans	515,711
2	Pensions – other	2,024,673
3	Post-retirement benefits other than pensions (PBOP)	471,236
4	Post- employment benefit plans	(444,680)
5	Other (Specify)	
6	Medical/Dental	2,275,294
7	Various	183,797
8		
9		
10		
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	Total	**5,026,031**

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 billed to the Respondent by an affiliated company must be assigned to the particular operating 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 correct 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 Operation and Maintenance (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	9,679,239			9,679,239
34	Customer Accounts	3,710,473			3,710,473
35	Customer Service and Informational	3,212			3,212
36	Sales				
37	Administrative and General	4,906,769			4,906,769
38	TOTAL Operation (Total of lines 28 thru 37)	18,299,693			18,299,693
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	3,327,843			3,327,843

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)	3,327,843			3,327,843
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 of 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)	13,007,082			13,007,082
56	Customer Accounts (Total of line 34)	3,710,473			3,710,473
57	Customer Service and Informational (Total of line 35)	3,212			3,212
58	Sales (Total of line 36)				
59	Administrative and General (Total of lines 37 and 46)	4,906,769			4,906,769
60	Total Operation and Maintenance (Total of lines 50 thru 59)	21,627,536			21,627,536
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	21,627,536			21,627,536
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	5,183,472			5,183,472
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	5,183,472			5,183,472
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	441,282			441,282
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	441,282			441,282
75	Other Accounts (Specify) (footnote details)	755,586			755,586
76	TOTAL Other Accounts	755,586			755,586
77	TOTAL SALARIES AND WAGES	28,007,876			28,007,876

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Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 partnership, 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	Snelson Companies, Inc.	4,871,364
2	Northwest Metal Fabrication and Pipe, Inc.	4,467,310
3	Michels Corporation	1,655,815
4	Prosource Tech, Inc.	1,019,154
5	Pilchuck Contractors, Inc.	555,824
6	Anchor QEA	456,414
7	Shannon & Wilson, Inc.	348,961
8	Resource Data, Inc.	284,432
9	Other	17,452,560
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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 or Services Provided by Affiliated Company			
2		IGC/MDU/MDU Resources	107	1,646,848
3		IGC/MDU/MDU Resources	426.1	8,104
4		IGC/MDU/MDU Resources	426.4	2,588
5		IGC/MDU/MDU Resources	813	218,752
6		IGC/MDU/MDU Resources	875	147,102
7		IGC/MDU/MDU Resources	880	600,826
8		IGC/MDU/MDU Resources	902	211,611
9		IGC/MDU/MDU Resources	903	4,120,305
10		IGC/MDU/MDU Resources	909	13,084
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Goods or Services Provided for Affiliated Company			
21		IGC/MDU/MDU Resources	920	3,909,844
22		IGC/MDU/MDU Resources	921	3,475,074
23		IGC/MDU/MDU Resources	922	(5,857)
24		IGC/MDU/MDU Resources	923	222,863
25		IGC/MDU/MDU Resources	925	966
26		IGC/MDU/MDU Resources	926	(265,615)
27		IGC/MDU/MDU Resources	930.1	21,639
28		IGC/MDU/MDU Resources	930.2	308,338
29		IGC/MDU/MDU Resources	931	1,237,514
30		IGC/MDU/MDU Resources	Various	416,793
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 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-owner, 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	1	1,350	2,000,730
2	Placed in Service: August 2001			
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Compressor Stations

Designate any station that was not operated during the past year. State in a 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 contemplated. 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 Number of Compressors Operated at Time of Station Peak (k)	Date of Station Peak (l)
1	1,089		142,278				1	
2								
3								
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5								
6								
7								
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 thru 13)			
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 thru 27)			

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Gas Storage Projects

1. On line 4, enter the total storage capacity certificated by FERC.
2. Report total amount in 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 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			
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25			

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	Date:			
2	Volumes of Gas Transported			
3	No-Notice Transportation			
4	Other Firm Transportation			
5	Interruptible Transportation			
6	Other (Describe) (footnote details)			
7	TOTAL			
8	Volumes of gas Withdrawn form Storage under Storage Contract			
9	No-Notice Storage			
10	Other Firm Storage			
11	Interruptible Storage			
12	Other (Describe) (footnote details)			
13	TOTAL			
14	Other Operational Activities			
15	Gas Withdrawn from Storage for System Operations			
16	Reduction in Line Pack			
17	Other (Describe) (footnote details)			
18	TOTAL			
19	SECTION B: CONSECUTIVE THREE-DAY PEAK DELIVERIES			
20	Dates:			
21	Volumes of Gas Transported			
22	No-Notice Transportation			
23	Other Firm Transportation			
24	Interruptible Transportation			
25	Other (Describe) (footnote details)			
26	TOTAL			
27	Volumes of Gas Withdrawn from Storage under Storage Contract			
28	No-Notice Storage			
29	Other Firm Storage			
30	Interruptible Storage			
31	Other (Describe) (footnote details)			
32	TOTAL			
33	Other Operational Activities			
34	Gas Withdrawn from Storage for System Operations			
35	Reduction in Line Pack			
36	Other (Describe) (footnote details)			
37	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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?
1	None				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
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15					
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27					
28					
29					
30					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2013	End of 2013/Q4

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 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 Three Months Ended Amount of Dth Quarterly Only (d)
01	Name of System:			
2	GAS RECEIVED			
3	Gas Purchases (Accounts 800-805)		30,239,746	
4	Gas of Others Received for Gathering (Account 489.1)	303		
5	Gas of Others Received for Transmission (Account 489.2)	305		
6	Gas of Others Received for Distribution (Account 489.3)	301		
7	Gas of Others Received for Contract Storage (Account 489.4)	307		
8	Gas of Others Received for Production/Extraction/Processing (Account 490 and 491)			
9	Exchanged Gas Received from Others (Account 806)	328		
10	Gas Received as Imbalances (Account 806)	328		
11	Receipts of Respondent's Gas Transported by Others (Account 858)	332		
12	Other Gas Withdrawn from Storage (Explain)		942,439	
13	Gas Received from Shippers as Compressor Station Fuel			
14	Gas Received from Shippers as Lost and Unaccounted for			
15	Other Receipts (Specify) (footnote details)		101,421,986	
16	Total Receipts (Total of lines 3 thru 15)		132,604,171	
17	GAS DELIVERED			
18	Gas Sales (Accounts 480-484)		30,190,159	
19	Deliveries of Gas Gathered for Others (Account 489.1)	303		
20	Deliveries of Gas Transported for Others (Account 489.2)	305	101,421,986	
21	Deliveries of Gas Distributed for Others (Account 489.3)	301		
22	Deliveries of Contract Storage Gas (Account 489.4)	307		
23	Gas of Others Delivered for Production/Extraction/Processing (Account 490 and 491)			
24	Exchange Gas Delivered to Others (Account 806)	328		
25	Gas Delivered as Imbalances (Account 806)	328		
26	Deliveries of Gas to Others for Transportation (Account 858)	332		
27	Other Gas Delivered to Storage (Explain)		1,014,618	
28	Gas Used for Compressor Station Fuel	509		
29	Other Deliveries and Gas Used for Other Operations		16,892	
30	Total Deliveries (Total of lines 18 thru 29)		132,643,655	
31	GAS LOSSES AND GAS UNACCOUNTED FOR			
32	Gas Losses and Gas Unaccounted For		(39,484)	
33	TOTALS			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of lines 30 and 32)		132,604,171	

Name of Respondent Cascade Natural Gas Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2013	Year/Period of Report 2013/Q4

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, stabilization 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 then this report. Bind the maps to the report.

See attached map


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

FOOTNOTE DATA

Schedule Page: 234 Line No.: 4 Column: i

Regulatory accounts related to FAS158 and OR rate change adjustments

FOOTNOTE DATA

Schedule Page: 260 Line No.: 12 Column: a

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 Medium Term Notes ranging from 7.95% to 8.01% totaling $24,000,000 due 2/2013

(2) 7.5% Notes were reacquired in March 2007 and refunded by 5.79% Senior Notes for $40,000,000 due 3/08/2037. The remaing unamortized debt expense of $1,229,120 was reclassified to unamortiexed loss on reacquired debt.

FOOTNOTE DATA

Schedule Page: 261 Line No.: 5 Column: a

CIAC		1,790,506
Eugene MGP expenses		34,178
263A Adjustment - UNICAP		6,324
Broken Meter interst charges		1,805
	Total	**1,832,813**

Schedule Page: 261 Line No.: 10 Column: a

Tax expense		8,513,849
Depreciation provision:		
Pre-1981		67,030
Post-1980		21,586,928
Vacation accrual - current year		1,482,153
Bad Debt expense		1,040,101
STIP accrual - addback		1,035,613
SFAS No. 87 accrual - SERP/SISP expense		760,070
Retiree Medical expense		658,733
SFAS No. 87 pension plan accrual		628,782
Amort of loss on reacquired debt (4281)		67,790
AFUDC Equity		563
Permanent diff's:		
50% of business meals & entertainment		170,189
Lobbying (5912.4264)		117,087
Interest expense		44,385
Penalties (5984)		679
	Total	**36,173,952**

Schedule Page: 261 Line No.: 20 Column: a

Depreciation & amortization of plant:		
Pre-1981		(326,329)
Post-1980		(39,199,201)
CC&B deduction		(1,567,992)
Deferred Gas costs		(3,982,994)
Funding of pension plan		(3,200,097)
Vacation accrual - prior year		(1,392,407)
Bad Debts written off		(1,210,155)
Bremerton MGP expenses		(1,138,279)
Tax Gain (loss) on disposal of assets:		
Pre-1981 assets		(88,417)
Post-1980 assets		(652,032)
Retiree Medical payments		(632,719)
SERP - benefit payments out of plan		(570,848)
Charitable contributions (5981.4261)		(295,886)
Customer advances - 2520.000 to 2520.2991		(86,313)
STIP accrual - prior year		(42,640)
Permanent diff's:		
401k dividends (MDUR)		(66,473)
SERP - perm difference piece		(907,832)
Oregon State income tax		42,373
	Total	**(55,318,241)**

Schedule Page: 261 Line No.: 33 Column: a

Allocated to:	409.1	409.2	Total
Washington	(353,117)	1,134	(351,983)
Oregon	(128,180)	369	(127,811)
Total	**(481,297)**	**1,503**	**(479,794)**

Schedule Page: 261 Line No.: 34 Column: a

Taxable Income for Federal Tax	(1,655,937)
Oregon adjustments to Federal Taxable Income:	
Oregon State Income Tax expense deducted from Federal Return	(42,373)
Bonus Depreciation adjustment	(1,073,298)
Post-80 gain adjustment	(16,095)
Taxable Income for Oregon Tax	(2,787,703)
Oregon Apportionment Factor	20.0000%
Oregon Taxable Income	(557,541)
Oregon Tax Rate	7.60%
Estimated Tax Return Oregon Income Tax	(42,373)
Adjustments:	
Difference between 12/31/12 accrual and tax return	792
Provision for Current Oregon Income Tax	**(41,581)**

Allocated to:	409.1	409.2	Total
Total	**(41,718)**	**137**	**(41,581)**

Schedule Page: 276 Line No.: 4 Column: g

Regulatory accounts relatated to FAS158 and deferred tax effect of OR State tax rate increase.

Schedule Page: 338 Line No.: 9 Column: a

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	17,519		5,729	
Manufactured gas production	0		0	
Transmission plant	11,160	1.88%	5,869	1.91%
Distribution plant	526,186	2.64%	147,953	2.61%
General plant	37,897	4.14%	12,488	4.01%
Total -	592,762	2.84%	172,039	2.82%

FOOTNOTE DATA

Schedule Page: 354 Line No.: 75 Column: a

PTO/Incentive/Severence Liability	$747,218
Miscellaneous	$8,368
Total Other Accounts	$755,586

INDEX

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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** 2013/Q4

ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FROM 2
FOR MULTI-STATE GAS COMPANIES
2013

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, 2013**

STATE OF OREGON - STATEMENT OF OPERATING INCOME FOR THE YEAR

LINE NO.	ACCOUNT (a)	(REF.) PAGE NO. (b)	GAS UTILITY Current Year (c)	 Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	65,973,539	68,132,016
3	Operating Expenses			
4	Operation Expenses (401)	4-9	46,891,609	49,459,374
5	Maintenance Expenses (402)	4-9	1,241,537	1,132,300
6	Depreciation Expense (403)	10	4,236,245	4,116,669
7	Amortization & Depletion of Utility Plant (404-405)	10	373,955	226,647
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
11	Taxes Other Than Income Taxes (408.1)	11	4,611,092	4,679,074
12	Income Taxes - Federal (409.1)	12	(128,180)	(318,693)
13	Income Taxes - Other (409.1)	13	(41,718)	(87,115)
14	Provision for Deferred Income Taxes (410.1)	14-21	2,773,923	2,890,050
15	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	14-21	-	-
16	Investment Tax Credit Adjustment - Net (411.4)	22	(14,885)	(4,372)
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)		59,943,578	$ 62,462,693
20	Net Utility Operating Income (Enter Total of line 2 less 19)		6,029,961	$ 5,669,323

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, 2013**

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	$ 35,823,358	$ 36,929,039	4,017,779	3,609,192	56,291	55,366
3	481 Commercial and Industrial Sales						
4	Small or Commercial	$ 22,006,650	$ 22,747,154	2,913,497	2,582,198	9,514	9,405
5	Large or Industrial	$ 3,947,263	$ 4,214,339	598,007	548,722	113	98
6	482 Other Sales to Public Authorities						
7	484 Interdepartmental Sales						
8	TOTAL Sales to Ultimate Consumers	$ 61,777,271	$ 63,890,532	7,529,283	6,740,112	65,918	64,869
9	483 Sales for Resale						
10	TOTAL Natural Gas Service Revenues	$ 61,777,271	$ 63,890,532	7,529,283	6,740,112	65,918	64,869
11	Revenues from Manufactured Gas						
12	TOTAL Gas Service Revenues	$ 61,777,271	$ 63,890,532				
13	OTHER OPERATING REVENUES						
14	485 Intracompany Transfers						
15	487 Forfeited Discounts						
16	488 Miscellaneous Service Revenues	$ 169,462	$ 200,825				
17	489 Revenue from Trans. of Gas of Others	$ 3,966,440	$ 4,012,257				
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	$ 11,000				
22	494 Interdepartmental Rents						
23	495 Other Gas Revenues	$ 49,365	$ 17,402				
24	TOTAL Other Operating Revenues	$ 4,196,268	$ 4,241,484				
25	TOTAL Gas Operating Revenues	$ 65,973,539	$ 68,132,016				
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)*	$ 57,830,008		6,931,276			
29	Main Line Industrial Sales *(Incl. Main Line Sales to Public Authorities)*	$ 3,947,263		598,007			
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))*	$ 61,777,271		7,529,283			

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, 2013**

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)	MANUFACTURED GAS PROPERTY (d)
	<u>Account 493</u>			
	Stone Bros., Inc.	Northern portion of parking lot at the Hermiston office for a latte stand	$ 11,000	
	Walla Walla Cnty commissoners		$ 49	
	Allocation of Rent Paid by MDUR Group		$ -	
	Total Account 493		$ 11,049	

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, 2013**

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	0	0
8	751 Production Maps and Records	0	0
9	752 Gas Wells Expenses	0	0
10	753 Field Lines Expenses	0	0
11	754 Field Compressor Station Expenses	0	0
12	755 Field Compressor Station Fuel and Power	0	0
13	756 Field Measuring and Regulating Station Expenses	0	0
14	757 Purification Expenses	0	0
15	758 Gas Well Royalties	0	0
16	759 Other Expenses	0	0
17	760 Rents	0	0
18	Total Operation (Enter Total of lines 7 thru 17)	0	0
19	Maintenance		
20	761 Maintenance Supervision and Engineering	0	0
21	762 Maintenance of Structures and Improvements	0	0
22	763 Maintenance of Producing Gas Wells	0	0
23	764 Maintenance of Field Lines	0	0
24	765 Maintenance of Field Compressor Station Equipment	0	0
25	766 Maintenance of Field Meas. and Reg. Sta. Equipment	0	0
26	767 Maintenance of Purification Equipment	0	0
27	768 Maintenance of Drilling and Cleaning Equipment	0	0
28	769 Maintenance of Other Equipment	0	0
29	TOTAL Maintenance (Enter Total of lines 20 thru 28)	0	0
30	TOTAL Natural Gas Production & Gathering (Total of lines 18 and 29)	0	0
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering	0	0
34	771 Operation Labor	0	0
35	772 Gas Shrinkage	0	0
36	773 Fuel	0	0
37	774 Power	0	0
38	775 Materials	0	0
39	776 Operation Supplies and Expenses	0	0
40	777 Gas Processed by Others	0	0
41	778 Royalties on Products Extracted	0	0
42	779 Marketing Expenses	0	0
43	780 Products Purchases for Resale	0	0
44	781 Variation in Products Inventory	0	0
45	(Less) 782 Extracted Products Used by the Utility - Credit	0	0
46	783 Rents	0	0
47	TOTAL Operation (Enter Total of lines 33 thru 46)	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, 2013**

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
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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	0	0
50	785 Maintenance of Structures and Improvements	0	0
51	786 Maintenance of Extraction and Refining Equipment	0	0
52	787 Maintenance of Pipe Lines	0	0
53	788 Maintenance of Extracted Products Storage Equipment	0	0
54	789 Maintenance of Compressor Equipment	0	0
55	790 Maintenance of Gas Measuring and Reg. Equipment	0	0
56	791 Maintenance of Other Equipment	0	0
57	TOTAL Maintenance (Enter Total of lines 49 thru 56)	0	0
58	TOTAL Products Extraction (Enter Total of lines 47 and 57)	0	0
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	0	0
62	796 Nonproductive Well Drilling	0	0
63	797 Abandoned Leases	0	0
64	798 Other Exploration	0	0
65	TOTAL Exploration & Development (Enter Total of lines 61 thru 64)	0	0
	D. Other Gas Supply Expenses		
66	Operation		
67	800 Natural Gas Well Head Purchases	0	0
68	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	0	0
69	801 Natural Gas Field Line Purchases	0	0
70	802 Natural Gas Gasoline Plant Outlet Purchases	0	0
71	803 Natural Gas Transmission Line Purchases	0	0
72	804 Natural Gas City Gate Purchases	41,411,200	34,578,421
73	804.1 Liquefied Natural Gas Purchases	0	0
74	805 Other Gas Purchases	0	0
75	(Less) 805.1 Purchased Gas Cost Adjustments	(5,284,552)	3,527,349
76	805.2 Incremental Gas Cost Adjustments	0	0
77	TOTAL Purchased Gas (Enter Total of lines 67 to 75)	36,126,648	38,105,770
78	806 Exchange Gas	0	0
79	Purchased Gas Expenses		
80	807.1 Well Expenses - Purchased Gas	0	0
81	807.2 Operation of Purchased Gas Measuring Stations	0	0
82	807.3 Maintenance of Purchased Gas Measuring Stations	0	0
83	807.4 Purchased Gas Calculations Expenses	0	0
84	807.5 Other Purchased Gas Expenses	0	0
85	TOTAL Purchased Gas Expenses (Enter Total of lines 80 thru 84)	0	0
86	808.1 Gas Withdrawn from Storage - Debit	389,993	235,533
87	(Less) 808.2 Gas Delivered to Storage - Credit	0	0
88	809.1 Withdrawals of Liquefied Natural Gas for Processing - Debit	0	0
89	(Less) 809.2 Deliveries of Natural Gas for Processing - Credit	0	0
90	(Less) Gas Used in Utility Operations - Credit		
91	810 Gas Used for Compressor Station Fuel - Credit	0	0
92	811 Gas Used for Products Extraction - Credit	0	0
93	812 Gas Used for Other Utility Operations - Credit	(23,371)	(25,871)
94	TOTAL Gas Used in Utility Operations - Credit (Lines 91 thru 93)	(23,371)	(25,871)
95	813 Other Gas Supply Expenses	91,827	53,084
96	TOTAL Other Gas Supply Exp (Lines 77, 78, 85, 86 thru 89, 94, 95)	36,585,097	38,368,516
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65 and 96)	36,585,097	38,368,516

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, 2013**

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	0	0
102	815 Maps and Records	0	0
103	816 Wells Expenses	0	0
104	817 Lines Expense	0	0
105	818 Compressor Station Expenses	0	0
106	819 Compressor Station Fuel and Power	0	0
107	820 Measuring and Regulating Station Expenses	0	0
108	821 Purification Expenses	0	0
109	822 Exploration and Development	0	0
110	823 Gas Losses	0	0
111	824 Other Expenses	0	0
112	825 Storage Well Royalties	0	0
113	826 Rents	0	0
114	TOTAL Operation (Enter Total of lines 101 thru 113)	0	0
115	Maintenance		
116	830 Maintenance Supervision and Engineering	0	0
117	831 Maintenance of Structures and Improvements	0	0
118	832 Maintenance of Reservoirs and Wells	0	0
119	833 Maintenance of Lines	0	0
120	834 Maintenance of Compressor Station Equipment	0	0
121	835 Maintenance of Measuring and Regulating Station Equipment	0	0
122	836 Maintenance of Purification Equipment	0	0
123	837 Maintenance of Other Equipment	0	0
124	TOTAL Maintenance (Enter Total of lines 116 thru 123)	0	0
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)	0	0
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering	0	0
129	841 Operation Labor and Expenses	0	0
130	842 Rents	0	0
131	842.1 Fuel	0	0
132	842.2 Power	0	0
133	842.3 Gas Losses	0	0
134	TOTAL Operation (Enter Total of lines 128 thru 133)	0	0
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	0	0
137	843.2 Maintenance of Structures and Improvements	0	0
138	843.3 Maintenance of Gas Holders	0	0
139	843.4 Maintenance of Purification Equipment	0	0
140	843.5 Maintenance of Liquefaction Equipment	0	0
141	843.6 Maintenance of Vaporizing Equipment	0	0
142	843.7 Maintenance of Compressor Equipment	0	0
143	843.8 Maintenance of Measuring and Regulating Equipment	0	0
144	843.9 Maintenance of Other Equipment	0	0
145	TOTAL Maintenance (Enter Total of lines 136 thru 144)	0	0
146	TOTAL Other Storage Expenses (Enter Total of lines 134 and 145)	0	0

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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	0	0
150	844.2 LNG Processing Terminal Labor and Expenses	0	0
151	844.3 Liquefaction Processing Labor and Expenses	0	0
152	844.4 Liquefaction Transportation Labor and Expenses	0	0
153	844.5 Measuring and Regulation Labor and Expenses	0	0
154	844.6 Compressor Station Labor and Expenses	0	0
155	844.7 Communication System Expenses	0	0
156	844.8 System Control and Load Dispatching	0	0
157	845.1 Fuel	0	0
158	845.2 Power	0	0
159	845.3 Rents	0	0
160	845.4 Demurrage Charges	0	0
161	(Less) 845.5 Wharfage Receipts - Credit	0	0
162	845.6 Processing Liquefied or Vaporized Gas by Others	0	0
163	846.1 Gas Losses	0	0
164	846.2 Other Expenses	0	0
165	TOTAL Operation (Enter Total of lines 149 thru 164)	0	0
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	0	0
168	847.2 Maintenance of Structures and Improvements	0	0
169	847.3 Maintenance of LNG Processing Terminal Equipment	0	0
170	847.4 Maintenance of LNG Transportation Equipment	0	0
171	847.5 Maintenance of Measuring and Regulating Equipment	0	0
172	847.6 Maintenance of Compressor Station Equipment	0	0
173	847.7 Maintenance of Communication Equipment	0	0
174	847.8 Maintenance of Other Equipment	0	0
175	TOTAL Maintenance (Enter Total of lines 167 thru 174)	0	0
176	TOTAL Liquefied Nat Gas Terminaling & Process Exp (Lines 165 & 175)	0	0
177	TOTAL Natural Gas Storage (Enter Total of lines 125, 146, and 176)	0	0
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	0	0
181	851 System Control and Load Dispatching	0	0
182	852 Communication System Expenses	0	0
183	853 Compressor Station Labor and Expenses	0	0
184	854 Gas for Compressor Station Fuel	0	0
185	855 Other Fuel and Power for Compressor Stations	0	0
186	856 Mains Expenses	0	0
187	857 Measuring and Regulating Station Expenses	0	0
188	858 Transmission and Compression of Gas by Others	0	0
189	859 Other Expenses	0	0
190	860 Rents	0	0
191	TOTAL Operation (Enter Total of lines 180 thru 190)	0	0
192	Maintenance		
193	861 Maintenance Supervision and Engineering	0	0
194	862 Maintenance of Structures and Improvements	0	0
195	863 Maintenance of Mains	0	0
196	864 Maintenance of Compressor Station Equipment	0	0
197	865 Maintenance of Measuring and Reg. Station Equipment	0	0
198	866 Maintenance of Communication Equipment	0	0
199	867 Maintenance of Other Equipment	0	0
200	TOTAL Maintenance (Enter Total of lines 193 thru 199)	0	0
201	TOTAL Transmission Expenses (Enter Total of lines 191 and 200)	0	0

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
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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	463,289	298,757
205	871 Distribution Load Dispatching	114,637	116,980
206	872 Compressor Station Labor and Expenses	56	0
207	873 Compressor Station Fuel and Power	0	0
208	874 Mains and Services Expenses	1,062,025	994,877
209	875 Measuring and Regulating Station Expenses - General	206,202	250,699
210	876 Measuring and Regulating Station Expenses - Industrial	28,584	30,404
211	877 Measuring & Regulating Station Exp - City Gate Check Station		
212	878 Meter and House Regulator Expenses	470,569	339,828
213	879 Customer Installations Expenses	421,774	483,068
214	880 Other Expenses	1,072,594	1,088,039
215	881 Rents	14,529	21,279
216	TOTAL Operation (Enter Total of lines 204 thru 215)	3,854,259	3,623,931
217	Maintenance		
218	885 Maintenance Supervision and Engineering	127,384	22,846
219	886 Maintenance of Structures and Improvements	186	310
220	887 Maintenance of Mains	307,513	282,840
221	888 Maintenance of Compressor Station Equipment	25	1,455
222	889 Maintenance of Meas. and Reg. Sta. Equip. - General	141,025	96,662
223	890 Maintenance of Meas. and Reg. Sta. Equip. - Industrial	31,431	18,542
224	891 Maint. of Meas. & Reg. Sta. Equip. - City Gate Check Station	0	0
225	892 Maintenance of Services	301,088	282,848
226	893 Maintenance of Meters and House Regulators	309,918	252,956
227	894 Maintenance of Other Equipment	46,028	139,225
228	TOTAL Maintenance (Enter Total of lines 218 thru 227)	1,264,598	1,097,684
229	TOTAL Distribution Expenses (Enter Total of lines 216 and 228)	5,118,857	4,721,615
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	7,442	13,531
233	902 Meter Reading Expenses	203,964	135,782
234	903 Customer Records and Collection Expenses	1,005,465	1,107,603
235	904 Uncollectible Accounts	261,624	693,641
236	905 Miscellaneous Customer Accounts Expenses	2,266	34,793
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	1,480,761	1,985,350
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	856,161	571,504
242	909 Informational and Instructional Expenses	6,775	28,236
243	910 Miscellaneous Customer Service and Informational Expenses	0	0
244	TOTAL Customer Service & Information Expenses (Lines 240 thru 243)	862,936	599,740
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	0	0
249	913 Advertising Expenses	807	2,591
250	916 Miscellaneous Sales Expenses	0	0
251	TOTAL Sales Expenses (Enter Total of lines 247 thru 250)	807	2,591

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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	1,543,517	1,541,917
255	921 Office Supplies and Expenses	1,250,190	1,269,742
256	(Less) 922 Administrative Expenses Transferred - Cr.	(142,874)	(141,164)
257	923 Outside Services Employed	185,437	208,394
258	924 Property Insurance	19,210	17,902
259	925 Injuries and Damages	(545,192)	280,335
260	926 Employee Pensions and Benefits	1,232,815	1,165,082
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	0	646
263	(Less) 929 Duplicate Charges - Cr.	0	0
264	930.1 General Advertising Expenses	25,821	15,804
265	930.2 Miscellaneous General Expenses	167,815	156,046
266	931 Rents	371,010	364,542
267	TOTAL Operation (Enter Total lines 254 thru 266)	4,107,749	4,879,246
268	Maintenance		
269	935 Maintenance of General Plant	(23,061)	34,616
270	TOTAL Administrative and General Exp (Total of lines 267 and 269)	4,084,688	4,913,862
271	TOTAL Gas O. & M. Exp (Lines 97,177,201,229,237,244,251 and 270)	48,133,146	50,591,674

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	0	0	0
274	Natural Gas:		0	0
275	Production and Gathering		0	0
276	Products Extraction			0
277	Exploration and Dev			0
278	TOTAL Natural Gas			0
279	Other Gas Supply Expenses	36,585,097	0	36,585,097
280	TOTAL Production	36,585,097	0	36,585,097
281	Underground Storage			
282	Other Storage			0
283	LNG Terminiling and Processing			0
284	Transmission Expenses			0
285	Distribution Expenses	3,854,259	1,264,598	5,118,857
286	Customer Accounts Expenses	1,480,761	0	1,480,761
287	Customer Service and Informational Expenses	862,936	0	862,936
288	Sales Expenses	807	0	807
289	Admin and General Expenses	4,107,749	(23,061)	4,084,688
290	TOTAL Gas O. & M. Expenses	46,891,609	1,241,537	48,133,146

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, 2013

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			373,955			373,955
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	111,828					111,828
9	Distribution Plant	3,857,904					3,857,904
10	General Plant	266,513					266,513
11	Common Plant - Gas						-
12							
13							
14							
15							
16							
17							
18							
19	**TOTAL**	**4,236,245**	**-**	**373,955**	**-**	**-**	**4,610,200**

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, 2013**

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

LINE NO.	KIND OF TAX (a)	AMOUNT (b)
1	Property Tax	1,345,199
2	Payroll Taxes	480,348
3	Oregon PUC Regulatory Fee	170,330
4	Oregon Department of Energy Fee	55,657
5	City Franchise Taxes	2,540,211
6	Miscellaneous Taxes	19,347
	TOTAL (Must agree with page 1, line 11)	**4,611,092**

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, 2013

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.	PARTICULARS (Details) (a)			Amount (b)
1	Gas Operating Revenues			279,314,948
2	Operations and Maintenance Expenses			(199,059,751)
3	Taxes, Other than Income			(26,544,454)
4	State Income (Excise) Tax			42,373
5	Interest			(8,832,242)
6	Other Income			(277,975)
7	Federal Income Tax Depreciation			
8	Pre-1981			(326,329)
9	Post-1980			(39,199,201)
10	Other Additions (Subtractions) to Derive Taxable Income			
11	CIAC			1,790,506
12	Book depreciation included in O&M			972,006
13	Tax Gain (loss) on disposal of assets:			
14	Pre-1981 assets			(88,417)
15	Post-1980 assets			(652,032)
16	Vacation Accrual adjustment			89,747
17	Retiree Medical Accrual adjustment			26,014
18	Amort of loss on reacquired debt (4281)			67,790
19	SFAS No.87 pension plan accrual			(2,571,315)
20	SFAS No.87 accrual-SERP DO add back bk expense			189,222
21	SERP-perm difference piece			(907,832)
22	Bad Debt Adjustment			(170,054)
23	Charitable Contributions (5981.4261)			(295,886)
24	Permanent diff's			
25	50 % of business meals & entertainment			170,188
26	Penalties (5984)			679
27	Lobbying (5912.4264)			117,087
28	Tax exempt interest			44,385
29	Interest capitalized adj (IRS>books)			251,377
30	Customer Advances - 2520.000 to 2520.2991			(86,313)
31	CC&B Deduction			(1,567,992)
32	263A Adjustment - UNICAP			6,324
33	401K Dividends (MDUR)			(66,473)
34	Severance accrual adjustment			-
35	STIP accrual adjustment			992,973
36	Deferred Gas Costs			(3,982,994)
37	Royalty Income (15% of royalty income receipts)			-
38	Broken Meter interest charges			1,805
39	Installment sale - Seattle GO			-
40	Bremerton MGP expenses			(1,138,279)
41	Eugene MGP expenses			34,178
42	Federal Tax Net Income			(1,655,937)
43	Show Computation of Tax:			
44	Federal Tax Rate			35%
45	Estimated Federal Tax			(579,578)
46	Adjustments to Estimated Federal Tax			
47	Difference between 12/31/11 accrual and tax return			99,784
48	Audit adjustment			-
49	Provision for Current Federal Income Tax			(479,794)
50	Allocated to:	409.1	409.2	Total
51	Washington	(353,117)	1,134	(351,983)
52	Oregon	(128,180)	369	(127,811)
53	Total	**(481,297)**	**1,503**	**(479,794)**

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, 2013

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			279,314,948
2	Operations and Maintenance Expenses			(199,059,751)
3	Taxes, Other than Income			(26,544,454)
4	State Income (Excise) Tax			
5	Interest			(8,832,242)
6	Other Income			(277,975)
7	Federal Income Tax Depreciation			
8	Pre-1981			(326,329)
9	Post-1980			(40,272,499)
10	Other Additions (Subtractions) to Derive Taxable Income			
11	CIAC			1,790,506
12	Tax Gain (loss) on disposal of assets:			972,006
13	Tax Gain (loss) on disposal of assets:			
14	Pre-1981 assets			(88,417)
15	Post-1980 assets			(668,127)
16	Vacation Accrual adjustment			89,747
17	Retiree Medical Accrual adjustment			26,014
18	Amort of loss on reacquired debt (4281)			67,790
19	SFAS No.87 pension plan accrual			(2,571,315)
20	SFAS No.87 accrual-SERP DO add back bk expense			189,222
21	SERP-perm difference piece			(907,832)
22	Bad Debt Adjustment			(170,054)
23	Charitable Contributions (5981.4261)			(295,886)
24	Permanent diff's			-
25	50 % of business meals & entertainment			170,188
26	Penalties (5984)			679
27	Lobbying (5912.4264)			117,087
28	Tax exempt interest			44,385
29	Interest capitalized adj (IRS>books)			251,377
30	Customer Advances - 2520.000 to 2520.2991			(86,313)
31	CC&B Deduction			(1,567,992)
32	263A Adjustment - UNICAP			6,324
33	401K Dividends (MDUR)			(66,473)
34	Severance accrual adjustment			-
35	STIP accrual adjustment			992,973
36	Deferred Gas Costs			(3,982,994)
37	Royalty Income (15% of royalty income receipts)			-
38	Broken Meter interest charges			1,805
39	Installment sale - Seattle GO			-
40	Bremerton MGP expenses deferred			(1,138,279)
41	Eugene MGP expenses deferred			34,178
42	Federal Tax Net Income			(2,787,703)
43	Oregon Apportionment Rate			20%
44	State Tax Net Income			(557,541)
45	Show Computation of Tax:			
46	State Tax Rate			7.6%
47				(42,373)
48	Adjustments to Estimated Federal Tax			
49	Difference between 12/31/12 accrual and tax return			792
50	Audit adjustment			-
51	Provision for Current Federal Income Tax			(41,581)
52	Allocated to:	409.1	409.2	Total
53	Oregon	**(41,718)**	**137**	(41,581)

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, 2013

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	27,838,248	1,652,969	-
6				
7	Other	-		
8	TOTAL GAS	27,838,248	1,652,969	-
9	Other (Specify)	-		
10	TOTAL (Account 190)	27,838,248	1,652,969	-
11	Classification of Totals			
12	Federal Income Tax	26,662,464	1,586,762	-
13	State Income Tax	1,175,784	66,207	-
14	Local Income Tax	-	-	-
15				
16	Amounts assigned to jurisdictions as follows:			
17	Federal Income Tax - Washington	See Below	1,163,424	-
18	Federal Income Tax - Oregon	See Below	423,338	-
19	State Income Tax - Oregon	1,175,784	66,207	-
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	26,662,464	20,039,172
	-	-
Balance to be allocated	26,662,464	20,039,172
Washington allocation factor	75.47%	75.45%
Washington Allocated balance	20,122,162	15,119,555
Oregon allocation factor	24.53%	24.55%
Oregon Allocated balance	6,540,302	4,919,617

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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	Amounts	DEBITS		CREDITS		End	
Debited to	Credited to	Account No.	Amount	Account No.	Amount	of Year	Line
Account 410.2	Account 411.2						No.
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
						-	1
							2
							3
							4
-	-		-	Regulatory accounts related to FAS 158 and OR rate change adjustments	(5,258,635)	20,926,644	5
							6
						-	7
-	-		-		(5,258,635)	20,926,644	8
						-	9
-	-		-		(5,258,635)	20,926,644	10
							11
-	-		-		(5,036,530)	20,039,172	12
-	-		-		(222,105)	887,472	13
-	-		-		-	-	14
							15
							16
-	-		-		(3,692,811)	See Below	17
-	-		-		(1,343,719)	See Below	18
-	-		-		(222,105)	887,472	19
							20
							21
							22

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, 2013**

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, 2013**

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.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	DEBITS		CREDITS			
		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, 2013**

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)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	-		
3	Gas	(77,797,048)	(5,939,706)	-
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(77,797,048)	(5,939,706)	-
6	Other (Specify)	-		
7				
8				
9	Total (Account 282) Lines 5 thru 8	(77,797,048)	(5,939,706)	-
10	Classification of Totals			
11	Federal Income Tax	(75,123,911)	(5,606,450)	-
12	State Income Tax	(2,673,137)	(333,256)	-
13	Local Income Tax	-	-	-

Amounts assigned to jurisdictions as follows:

Federal Income Tax - Washington	See Below	(4,110,679)	-
Federal Income Tax - Oregon	See Below	(1,495,771)	-
State Income Tax - Oregon	(2,673,137)	(333,256)	-

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	(79,224,881)	(84,824,483)
Washington allocation factor	76.07%	76.48%
Washington Allocated balance relating to utility plant for ratemaking	(60,266,367)	(64,873,765)
Oregon allocation factor	23.93%	23.52%
Oregon Allocated balance relating to utility plant for ratemaking	(18,958,514)	(19,950,718)
Remaining balance to be allocated on Utility Plant	4,100,970	3,508,761
Oregon allocation factor	22.74%	22.57%
Oregon allocation	932,561	791,927
Plus Oregon Allocation of utility plant for ratemaking related balance	(18,958,514)	(19,950,718)
Total Oregon Allocated Balance	(18,025,953)	(19,158,791)

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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		CREDITS			
		Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
						-	2
-	-	182.3	215,298	254	585,361	(84,106,817)	3
						-	4
-	-		215,298		585,361	(84,106,817)	5
						-	6
							7
							8
-	-		215,298		585,361	(84,106,817)	9
							10
-	-	182.3	-	254	585,361	(81,315,722)	11
-	-	182.3	215,298	254	-	(2,791,095)	12
-	-		-		-	-	13
-	-		-		429,190	See Below	
-	-		-		156,171	See Below	
-	-		215,298		-	(2,791,095)	

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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)	Amounts Credited Account 411.1 (d)
1	Account 283			
2	Electric			
3	Gas	(31,976,752)	(1,505,837)	-
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(31,976,752)	(1,505,837)	-
6	Other (Specify)	-		
7				
8				
9	Total (Account 283) Lines 5 thru 8	(31,976,752)	(1,505,837)	-
10	Classification of Totals			
11	Federal Income Tax	(30,235,293)	(1,432,733)	-
12	State Income Tax	(1,741,459)	(73,104)	-
13	Local Income Tax	-	-	-
	Amounts assigned to jurisdictions as follows:			
	Federal Income Tax - Washington	See below	(1,050,488)	-
	Federal Income Tax - Oregon	See below	(382,245)	-
	State Income Tax - Oregon	(1,741,459)	(73,104)	-

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	(350,520)	(327,154)
Washington allocation factor	76.07%	76.48%
Washington Allocated balance relating to Debt Refinancing	(266,641)	(250,207)
Oregon allocation factor	23.93%	23.52%
Oregon Allocated balance relating to Debt Refinancing	(83,879)	(76,947)
Remaining balance to be allocated on 3-factor	(29,884,773)	(26,308,836)
Oregon allocation factor	24.53%	24.55%
Oregon allocation	(7,330,735)	(6,458,819)
Plus Oregon Allocation of Debt refinancing related balance	(83,879)	(76,947)
Total Oregon Allocated Balance	(7,414,614)	(6,535,766)

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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)	
							1
							2
-	-	Regulatory accounts related to FAS 158 and deferred tax effect of OR State Tax Rate increase	5,286,538		-	(28,196,051)	3
						-	4
-	-		5,286,538		-	(28,196,051)	5
						-	6
							7
							8
-	-		5,286,538		-	(28,196,051)	9
							10
-	-		5,032,036		-	(26,635,990)	11
-	-		254,502			(1,560,061)	12
-	-		-		-	-	13
-	-		3,689,516		-	See below	
-	-		1,342,520		-	See below	
-	-		254,502		-	(1,560,061)	

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
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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 (a)	Balance at Beginning of Year (b)	Deferred For Year: Account No (c)	Deferred For Year: Amount (d)	Allocations to Current Year's Income: Account No (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)	Balance at End of Year (h)	Average period of Allocation to Income (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	(14,885)		ALLOCATED	23 Years
6	Total	0		0		(14,885)			
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, 2013

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)	160,341,264		160,341,264			
4	Property under capital leases	-					
5	Plant purchased or sold	-					
6	Completed construction not classified	2,520,997		2,520,997			
7	Experimental plant unclassified	-					
8	TOTAL (Enter Total of lines 3 thru 7)	162,862,261	-	162,862,261	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	112,034		112,034			
12	Acquisition Adjustments	-					
13	Total Utility Plant (Enter Total of lines 8 thru 12)	162,974,295	-	162,974,295	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(78,164,999)		(78,164,999)			
15	Net Utility Plant (Line 13 less 14)	84,809,296	-	84,809,296	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(78,164,999)		(78,164,999)			
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)	(78,164,999)	-	(78,164,999)	-		-
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)	(78,164,999)	-	(78,164,999)	-		-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
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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, 2013

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	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 2013

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	-	(6,573)	0	-	41,975
85	370	Communications Equipment	-					-
86	371	Other Equipment	-					-
87		TOTAL Transmission Plant	5,888,292	-	(6,573)	0	-	5,881,719
88		5. Distribution Plant						
89	374	Land and Land Rights	224,630	19,389	-	-	-	244,019
90	375	Structures and Improvements	326,674	38,330	-	-	-	365,004
91	376	Mains	70,368,616	3,290,431	(39,252)	1	-	73,619,796
92	377	Compressor Station Equipment	-					-
93	378	Measuring and Regulating Equipment - General	7,472,201	232,477	(3,192)	-	-	7,701,486
94	379	Measuring and Regulating Equipment - City Gate	-					-
95	380	Services	39,446,010	2,782,418	(71,054)	-	-	42,157,374
96	381	Meters	11,652,727	316,685	(108,584)	(32)	-	11,860,796
97	382	Meter Installations	7,971,285	94,597	(2,357)	-	-	8,063,525
98	383	House Regulators	2,409,979	88,031	(44,016)	(76)	-	2,453,918
99	384	House Regulator Installations	-					-
100	385	Industrial Measuring and Regulating Station Equipment	1,458,302	74,019	-	-	-	1,532,321
101	386	Other Property on Customers' Premises	-					-
102	387	Other Equipment	-					-
102.a	388	ARO - Distribution	4,425	111	-	-	-	4,536
103		TOTAL Distribution Plant	141,334,849	6,936,488	(268,455)	(107)	-	148,002,775

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, 2013**

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	-	-	(0)	-	316,796
106	390	Structures and Improvements	3,163,403	46,141	-	(0)	-	3,209,544
107	391	Office Furniture and Equipment	187,771	-	(16,694)	1	-	171,078
108	392	Transportation Equipment	2,237,923	540,439	(312,157)	55,315	(132,767)	2,388,753
109	393	Stores Equipment	1,171	-	(1,172)	1	-	-
110	394	Tools, Shop and Garage Equipment	835,271	157,302	(1,193)		-	991,379
111	395	Laboratory Equipment	-					-
112	396	Power Operated Equipment	607,048	492,494	(426,343)	33,541	(3,200)	703,541
113	397	Communication Equipment	844,501	327,701	(58,637)	(1)	-	1,113,564
114	398	Miscellaneous Equipment	17,714	-	(8,265)	(4)	-	9,445
115		SUBTOTAL	8,211,598	1,564,077	(824,461)	88,853	(135,967)	8,904,100
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	8,211,598	1,564,077	(824,461)	88,853	(135,967)	8,904,100
118		TOTAL (Accounts 101 and 106)	155,508,406	8,500,565	(1,099,489)	88,746	(135,967)	162,862,261
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	155,508,406	8,500,565	(1,099,489)	88,746	(135,967)	162,862,261

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, 2013**

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
2				
3				
4				
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44				
45				
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, 2013**

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	Installation of mains, service lines, measuring and regulating stations,		
2	meter sets and telemetering, etc.		
3			
4			
5			
6	Installation of mains, service lines, measuring and regulating stations,	112,034	
7	meter sets and telemetering, etc.		
8			
9			
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43	T O T A L -	112,034	0

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, 2013

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	(74,956,224)	(74,956,224)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(4,111,500)	(4,111,500)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(219,817)	(219,817)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	1,043	1,043		
7.02	Other	-			
8		-			
9	TOTAL Depreciation Provisions for Year (*Enter total of lines 3 thru 8*)	(4,330,274)	(4,330,274)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	1,099,489	1,099,489		
12	Cost of Removal	204,970	204,970		
13	Salvage (credits)	(366,248)	(366,248)		
14	TOTAL Net Charges for Plant Retired (*enter Total of Lines 11 thru 13*)	938,211	938,211		
15	Other Debit or Credit Items (Describe)		28,676		
15.01	Increase/Decrease in Retirement Work in Progress	154,612	154,612		
15.02	Adjustment Due to Change in Allocation Rate	-			
16					
17	Balance End of Year (*Enter Total of Lines 1, 9, 14, 15, & 16*)	(78,164,999)	(78,164,999)		
	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	(2,733,316)	(2,733,316)		
25	Distribution	(72,016,032)	(72,016,032)		
26	General	(3,514,119)	(3,514,119)		
26.01	Intangible	(73,667)	(73,667)		
26.02	Retirement Work-In-Progress	172,135	172,135		
27	TOTAL (*Enter Total of Lines 18 thru 26*)	(78,164,999)	(78,164,999)		

Row 15 Other Debit or Credit due to transfer of assets, and related depreciation reserve between state jurisdictions

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, 2013**

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)	9,522,783		9,522,783			
4	Property Under Capital Leases	-					
5	Plant Purchased or Sold	-					
6	Completed Construction not Classified	328,841		328,841			
7	Experimental Plant Unclassified	-					
8	TOTAL (*Enter Total of lines 3 thru 7*)	9,851,624	-	9,851,624	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	1,053,867		1,053,867			
12	Acquisition Adjustments	-					
13	Total Utility Plant (*Lines 8 thru 12*)	10,905,491	-	10,905,491	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(3,399,359)		(3,399,359)			
15	Net Utility Plant (Line 13 less 14)	7,506,132	-	7,506,132	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(2,574,890)		(2,574,890)			
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	(824,469)		(824,469)			
22	Total In-Service (*Lines 18 thru 21*)	(3,399,359)	-	(3,399,359)	-		-
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*)	(3,399,359)	-	(3,399,359)	-		-

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, 2013**

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	37,302	-	-	30	-	37,332
3	302 Franchises and Consents	-					-
4	303 Miscellaneous Intangible Plant	4,168,791	1,445,749	-	3,399	-	5,617,939
5	TOTAL Intangible Plant	4,206,093	1,445,749	-	3,429	-	5,655,271
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 lLand 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, 2013

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 **CASCADE NATURAL GAS CORPORATION**	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2013

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	23,279	-	-	18	-	23,297
90	375	Structures and Improvements	97,921	-	-	80	-	98,001
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	121,200	-	-	98	-	121,298

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, 2013

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	159,952	-	-	(1,960)	-	157,992
106	390	Structures and Improvements	1,369,362	45,405	-	(18,595)	-	1,396,172
107	391	Office Furniture and Equipment	2,216,518	279,541	902,930	(8,042)	-	1,585,088
108	392	Transportation Equipment	244,441	14,541	41,244	(71,835)	210,279	356,182
109	393	Stores Equipment	10,692	-	120	7	-	10,578
110	394	Tools, Shop, and Garage Equipment	286,277	40,331	-	87	-	326,695
111	395	Laboratory Equipment	26,951	-	-	(249)	-	26,702
112	396	Power Operated Equipment	14,195	(2,993)	-	12	-	11,214
113	397	Communication Equipment	181,948	18,054	305	(2,415)	-	197,282
114	398	Miscellaneous Equipment	7,181	-	-	(31)	-	7,150
115		SUBTOTAL	4,517,517	394,879	944,599	(103,021)	210,279	4,075,055
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	4,517,517	394,879	944,599	(103,021)	210,279	4,075,055
118		TOTAL (Accounts 101 and 106)	8,844,810	1,840,627	944,599	(99,493)	210,279	9,851,625
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	8,844,810	1,840,627	944,599	(99,493)	210,279	9,851,625

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, 2013**

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	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2013

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	GIS Compliance Improvements	530,114	
2			
3	Other general plant work in progress expenditures	523,753	
4			
5			
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43	TOTAL -	1,053,867	0

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, 2013

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	(3,329,019)	(3,329,019)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(124,745)	(124,745)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(13,819)	(13,819)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	-	-		
7.02	Other	-			
8		-			
9	*8*)	(138,564)	(138,564)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	944,599	944,599		
12	Cost of Removal	-	-		
13	Salvage (credits)	(11,869)	(11,869)		
14	*13*)	932,730	932,730		
15	Other Debit or Credit Items (Describe)		(40,037)		
15.01	Increase/Decrease in Retirement Work in Progress	-	-		
15.02	Adjustment Due to Change in Allocation Rate	-			
16					
17	Balance End of Year (*Enter Total of Lines 1, 9, 14, 15, & 16*)	(2,574,890)	(2,574,890)		

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	-	-		
25	Distribution	(100,267)	(100,267)		
26	General	(2,474,623)	(2,474,623)		
26.01	Intangible	-	-		
26.02	Retirement Work-In-Progress	-	-		
27	TOTAL (*Total of Lines 18 thru 26*)	(2,574,890)	(2,574,890)		

Row 15 Other Debit or Credit due to transfer of assets, and related depreciation reserve between state jurisdictions

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, 2013

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)			$ 60,226		$ 60,226
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					
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					9,567
31	Amount per Mcf					6.30
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						
38						

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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, 2013

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 discontinued 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, 2013**

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**		
10			
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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, 2013**

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
						10.35	7,436,824	$ 27,586,957	370.95	2
										3
								$ 327,721	n/a	4
										5
								$ 8,211,970	n/a	6
										7
									n/a	8
							7,436,824	**$ 36,126,648**		9
										10
										11
										12
										13
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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, 2013

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 u 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.

LINE NO.	PURPOSE FOR WHICH GAS WAS USED (a)	ACCOUNT CHARGED (b)	Natural Gas: MCF OF GAS USED (14.73 PSIA AT 60 °F) (c)	Natural Gas: AMOUNT OF CREDIT (d)	Natural Gas: AMOUNT PER MCF (CENTS) (e)	Manufactured Gas: MCF OF GAS USED (14.73 PSIA AT 60 °F) (f)	Manufactured Gas: 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	5,852	$ 23,371	0	0	0
6	(Report separately for each principal use. Group minor uses).						
7							
8							
9							
10							
11							
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22							
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24							
25	**TOTAL**		5,852	$ 23,371			

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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, 2013**

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		7,442,676
11	f. LNG		
12	g. Other		
13	TOTAL GAS PURCHASED		7,442,676
14	Gas of others received for transportation		25,070,691
15	Receipts of respondents' gas transported or compressed by others		
16	Exchange gas received		
17	Gas withdrawn from underground storage		84,926
18	Gas received from LNG storage		
19	Gas received from LNG processing		
20	Other receipts: (specify)		
21	TOTAL RECEIPTS		32,598,293

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, 2013

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		598,006
39	(ii) Other distribution system sales		6,931,276
40	TOTAL DISTRIBUTION SYSTEM SALES		7,529,282
41	d. Interdepartmental sales		
42	TOTAL SALES		7,529,282
43			
44	Deliveries of gas transported or compressed for:		
45	a. Other interstate pipeline companies		
46	b. Others		25,070,691
47	TOTAL, GAS TRANSPORTED OR COMPRESSED FOR OTHERS		25,070,691
48	Deliveries of respondent's gas for transportation or compression by others		
49	Exchange gas delivered		
50	Natural gas used by respondent		5,852
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		32,605,825
57	Production system losses		
58	Storage losses		
59	Transmission system losses		
60	Distribution system losses		(7,532)
61	Other losses (specify in so far as possible)		
62	TOTAL UNACCOUNTED FOR		(7,532)
63	TOTAL SALES, OTHER DELIVERIES & UNACCOUNTED FOR		32,598,293

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, 2013**

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.	136,263	33,076	103,187
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)	248,182	60,929	187,253
6	Director's Fees (paid to MDU for CNGC's share of director's expenses)	298,393	73,255	225,138
7	Miscellaneous under $250,000 (6 items)	5,092	555	4,537
8				
9				
10				
	TOTAL	**687,930**	**167,815**	**520,115**

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, 2013

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	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2013

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, 2013**

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	1,646,848	404,301
2	MDU/MDUR Allocated - approved in Order 07-418	426.1	8,104	1,990
3	MDU/MDUR Allocated - approved in Order 07-418	426.4	2,588	635
4	MDU/MDUR Allocated - approved in Order 07-418	813	218,752	53,704
5	MDU/MDUR Allocated - approved in Order 07-418	875	147,102	36,113
6	MDU/MDUR Allocated - approved in Order 07-418	880	600,826	147,503
7	MDU/MDUR Allocated - approved in Order 07-418	902	211,611	51,951
8	MDU/MDUR Allocated - approved in Order 07-418	903	4,120,305	1,011,535
9	MDU/MDUR Allocated - approved in Order 07-418	909	13,084	3,212
10	MDU/MDUR Allocated - approved in Order 07-418	920	3,909,844	959,867
11	MDU/MDUR Allocated - approved in Order 07-418	921	3,475,074	853,131
12	MDU/MDUR Allocated - approved in Order 07-418	922	(5,857)	(1,438)
13	MDU/MDUR Allocated - approved in Order 07-418	923	222,863	54,713
18	MDU/MDUR Allocated - approved in Order 07-418	925	966	237
19	MDU/MDUR Allocated - approved in Order 07-418	926	(265,615)	(65,208)
20	MDU/MDUR Allocated - approved in Order 07-418	930.1	21,639	5,312
21	MDU/MDUR Allocated - approved in Order 07-418	930.2	308,338	75,697
22	MDU/MDUR Allocated - approved in Order 07-418	931	1,237,514	303,810
23	Other Services	VAR	416,793	302,397
	TOTALS		16,290,779	4,199,462

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, 2013**

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
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	MDU Resource Foundation (Bismark, ND)	426.1	58,322	13,717
3	CNGC Matching Contributions to Winter Help (WA and OR)	426.1	37,000	8,702
4	Boys & Girls Clubs (WA and OR)	426.1	9,000	2,264
5	American Red Cross (WA and OR)	426.1	7,750	1,764
6	United Way Drive (WA and OR)	426.1	5,285	1,306
7	Columbia Industries (WA and OR)	426.1	4,000	941
8	Habitat for Humanity (WA and OR)	426.1	2,750	970
9	The FDN For Private Enterprise (Federal Way, WA)	426.1	2,500	588
10	Other Organizations under $1,500 (13 organizations)	426.1/921	8,974	3,818
11	**Total contributions to and memberships in charitable organizations**		**135,581**	**34,070**
12				
13	*(e) All Other Organizations and Kinds of Donations and Contributions:*			
14	Bismarck Mandan Area Chamber of Commerce (Bismarck,ND)	426.1	20,800	4,892.00
15	MDU Resources expenses	426.1	8,550	2,011.00
16	Modern Living Services (WA)	426.1	6,000	1,176.00
17	Association of Washington Businesses (Olympia, WA)	426.1	5,000	1,176.00
18	Montana Dakota Utilities (MT, WY, ND,)	426.1	3,859	908.00
19	Tri-Cities Regional Chamber of Commerce (Tri-Cities, WA)	426.1	3,220	669
20	EDASC Foundation (WA)	426.1	2,000	-
21	Sisters Little League (OR)	426.1	1,500	1,500
22	Other Organizations under $1,000 (72 organizations)	426.1/930.2	94,284	27,757
23	**Total all other organizations and kinds of donations and contributions**		**145,213**	**40,089**
24				
25	*(b) Organizations of the Utility Industry:*			
26	American Gas Association (Washington D.C.)	930.2	124,783	29,349
27	Northwest Gas Association (West Linn, OR)	921	59,095	13,899
28	Pipeline Association for Public Awareness (WA, OR)	921	25,215	5,931
29	Other Organizations under $1,000 (1 organizations)	921	575	
30	**Total organizations of the utility industry**		**209,668**	**49,179**
31				
32				
33				
34				
35				
36				
37				
	TOTAL		**490,461**	**123,337**

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, 2013

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/	K. Frank Morehouse	4/	
2	Chairman of the Board 2/	David L. Goodin	4/	
3	Executive VP & General Manager 3/	Scott W. Madison	4/	
4	VP Operations	Eric P. Martuscelli	4/	
5	Vice President, Controller, Asst. Treasurer and Asst. Secretary 3/	Mark A. Chiles	4/	
6	Vice President-HR, Customer Service and Safety 1/	Anne M. Jones	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	Treasurer 2/	Douglass A. Mahowald	4/	
11	Executive VP -Utility Operations Support 1/	Michael J. Gardner	4/	
12	Executive VP-Business Dev & Gas Supply 1/	Dennis L. Haider	4/	
13				
14	1/ Salary includes amount allocated to CNGC from MDU			
15	2/ Salary includes amount allocated to CNGC from MDUR			
16	3/ Salary includes amount allocated to CNGC from IGC			
17	4/ Confidential salary data included on filed reports with OPUC.			
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, 2013

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	2,306,111
2	Prosource Tech Inc.	Consulting	107,896
3	Resource Data Inc	Consulting	66,898
4	Corrpro Companies Inc.	Construction	59,401
5	Express Employement Professional	Temporary Employment	51,097
6	Pilchuck Contractors Inc	Construction	49,573
7	Veris Law Group PLLC	Environmental	35,923
8	High Desert Aggregate & Paving Inc.	Construction	29,112
9	Other	Various	2,171,158
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
	TOTAL		**4,877,168**

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, 2013**

In order to help us with production of our Oregon Utility Statistics publication, please indicate:

Oregon Production Statistics(therms)	
Gas Produced	-
Gas Purchased	337,281,035
Total Receipts	337,281,035

Gas Sales	337,298,425
Gas used by Company	60,545
Gas Delivered to LNG Storage - Net	-
Losses & Billing Delay	(77,935)
Total Disbursements	337,281,035

Oregon Revenue by Service Class	
Residential	$ 35,823,359
Commercial & Industrial	$ 25,953,913
Firm	$ -
Interruptible	$ -
Transportation	$ 3,966,440
Total	$ 65,743,712

Gas Sold in Therms(Oregon)	
Residential	41,570,293
Commercial & Industrial	36,332,072
Firm	-
Interruptible	-
Transportation	259,396,060
Total	337,298,425

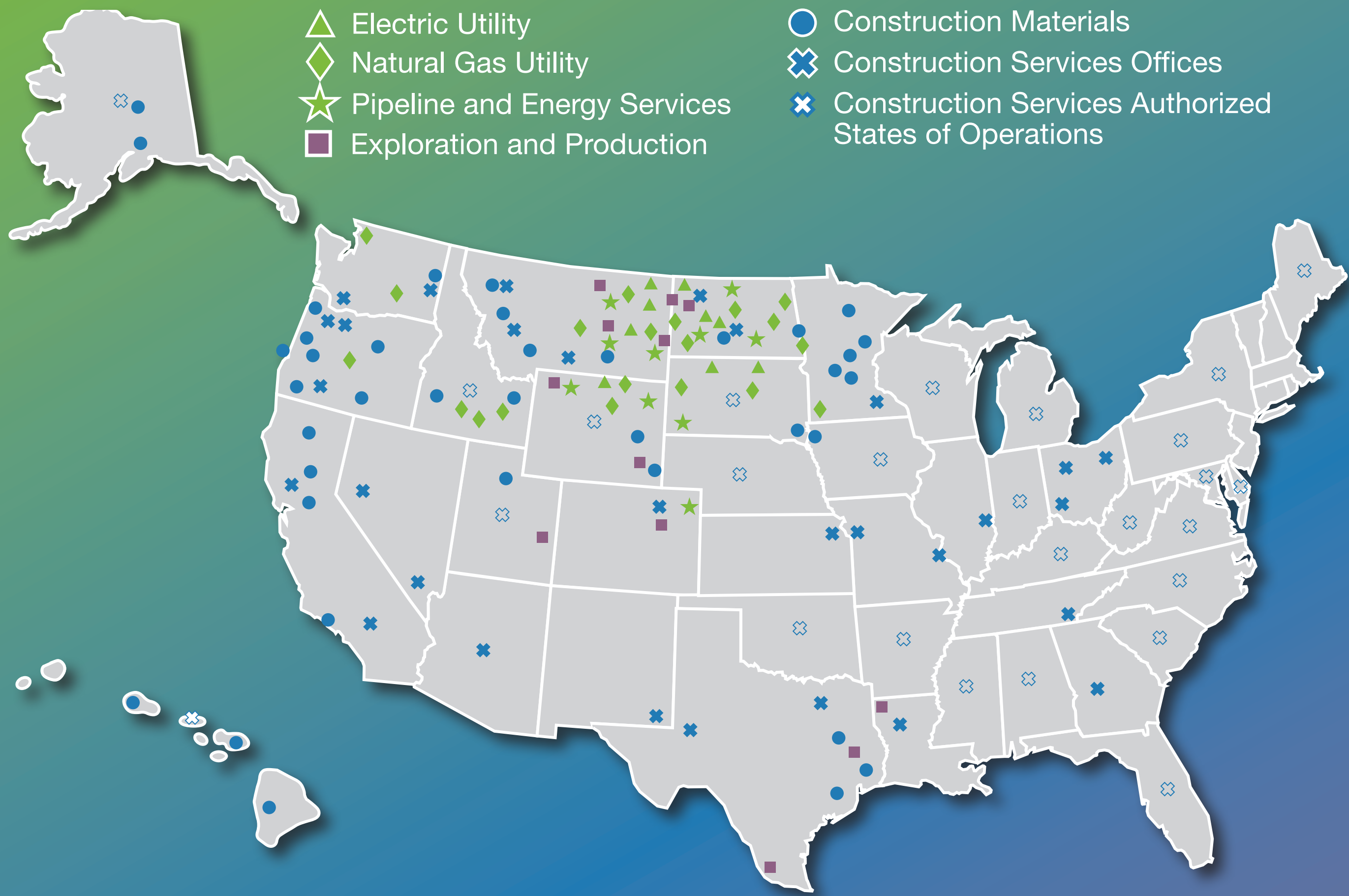
Average Number of Customers	
Residential	56,291
Commercial & Industrial	9,627
Firm	-
Interruptible	-
Transportation	35
Total	65,953

MDU Resources Group, Inc.

Building a Strong America®

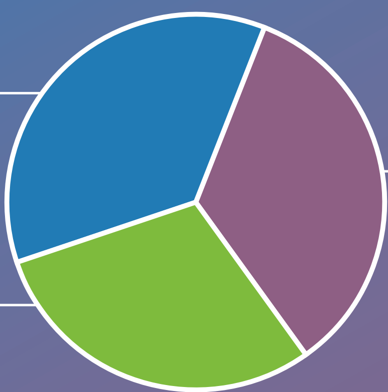
2013 Annual Report
Form 10-K
Proxy Statement

MDU Resources Group, Inc.



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.

2013 Earnings*

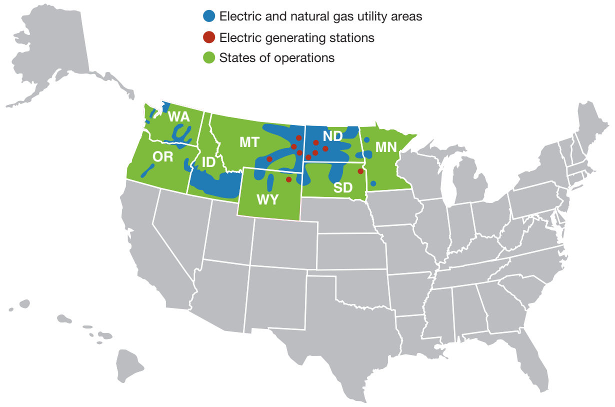


*Based on adjusted earnings, as noted on page 1, and excludes Other operations and eliminations.

Building a Strong America®

Territory	Company Description	2013 Highlights	2013 Key Statistics	A Look Ahead

REGULATED



Electric and Natural Gas Utilities

MDU Resources Group utility companies serve more than 1 million 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.

2013 Highlights

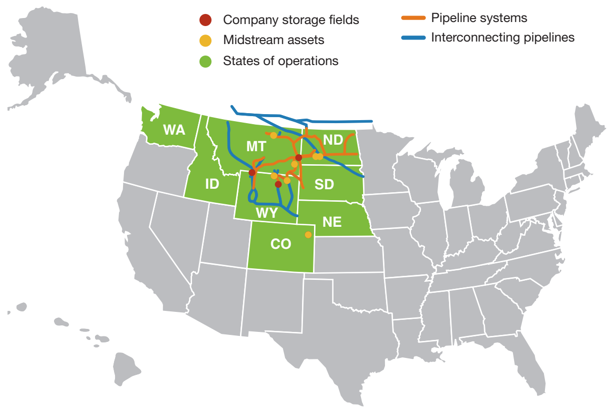
- *Continue to see utility customer growth, surpassing 1 million customers during 2013.*
- *Invested a record $267 million in capital projects in 2013.*
- *Construction continues on an 88-megawatt simple-cycle natural gas turbine, which is expected to be in service in third quarter 2014.*
- *Construction continues on an air quality control system at the Big Stone electric generating facility, with completion expected in 2015.*

2013 Key Statistics

Revenues (millions)	
Electric	$257.3
Natural gas	$851.9
Earnings (millions)	
Electric	$34.8
Natural gas	$37.7
Electric retail sales (million kWh)	3,173.1
Natural gas distribution (MMdk)	
Sales	108.3
Transportation	149.5
Corporate earnings contribution	
Electric	12%
Natural gas	13%

A Look Ahead

- *Investing a record amount in the utility operations for the third straight year, with about $300 million planned for 2014.*
- *Expecting rate base to grow approximately 9 percent compounded annually over the next five years, with plans for approximately $1.3 billion in capital investments.*
- *Expecting the 88-megawatt simple-cycle, natural gas-fired electric generating turbine at Heskett Station in Mandan, N.D., to be in service third quarter 2014.*



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 and processing facilities primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment is constructing Dakota Prairie Refining to refine Bakken crude oil and also provides cathodic protection and other energy-related services.

2013 Highlights

- *Began construction on the Dakota Prairie Refining, LLC refinery, with approximately 40 percent complete at the start of 2014. Total cost is expected to be about $350 million.*
- *WBI Energy Transmission filed its first rate case in 14 years, requesting the Federal Energy Regulatory Commission approve an increase of $28.9 million annually.*
- *Saw a full year of benefit from the 50 percent interest purchased in 2012 in Whiting Oil and Gas Corp.'s Pronghorn natural gas and oil midstream assets in the Bakken area.*

2013 Key Statistics

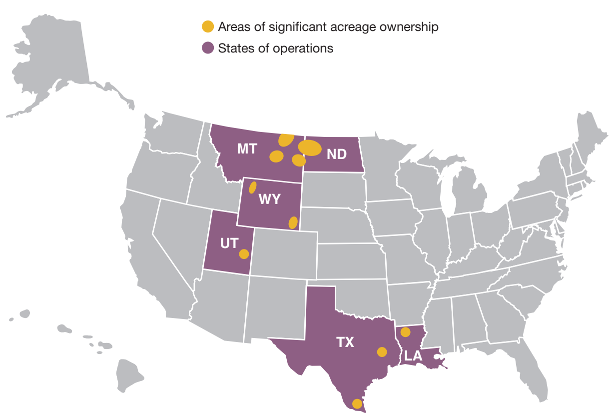
Revenues (millions)	$202.1
Earnings (millions)*	$15.1
Pipeline (MMdk)	
Transportation	178.6
Gathering	40.7
Corporate earnings contribution	5%

* *Excludes a $9.0 million after-tax natural gas gathering asset impairment and a $1.5 million net benefit related to natural gas gathering operations litigation.*

A Look Ahead

- *Planning a 375-mile natural gas pipeline that will transport 400 million cubic feet per day from western North Dakota to northwestern Minnesota. Construction could begin in 2016.*
- *Expecting the 20,000-barrel-per-day Dakota Prairie refinery to be operational by the end of 2014.*
- *Working on several pipeline projects in 2014, including connections for a natural gas processing plant in the Bakken area, an expansion of the company's transmission system to increase capacity to the Black Hills, and a 24-mile pipeline and related processing facilities to transport Fidelity Exploration & Production Company's Paradox Basin natural gas production.*

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/Gulf States regions of the United States.

2013 Highlights

- *Increased oil production by 30 percent. Oil production now makes up about 47 percent of total production, compared to 14 percent in 2007.*
- *More than tripled oil production in the Paradox Basin, compared to 2012 results.*
- *Had net oil production in the Bakken of about 7,900 barrels of oil per day in the fourth quarter.*

2013 Key Statistics

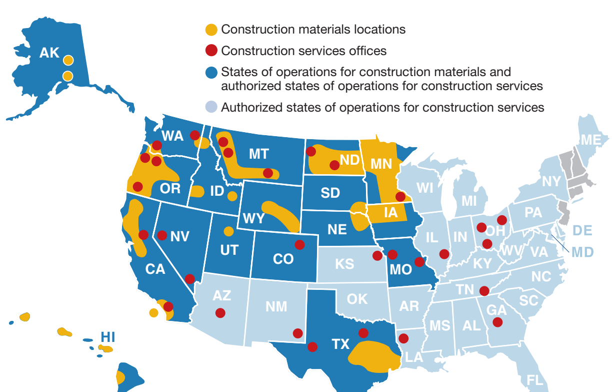
Revenues (millions)	$536.0
Earnings (millions)**	$98.4
Production	
Oil (MBbls)	4,815
Natural gas liquids (MBbls)	781
Natural gas (MMcf)	28,008
Proved reserves	
Oil (MBbls)	41,019
Natural gas liquids (MBbls)	6,602
Natural gas (MMcf)	198,445
Corporate earnings contribution	34%

** *Excludes a $3.9 million unrealized commodity derivatives loss.*

A Look Ahead

- *Planning approximately $440 million in capital spending for exploration and production in 2014, with significant expenditures in the Paradox Basin and the Bakken.*
- *Anticipating a 10 to 20 percent increase in oil production in 2014 compared to 2013.*
- *Continuing development in the Paradox Basin is expected to be a key contributor to the company's oil growth strategy. The company has approximately 130,000 net acres in the Paradox Basin, with an option to earn another 20,000.*

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.

2013 Highlights

- *Highest combined construction operation earnings since 2007, with a record year of earnings for the construction services division and the highest earnings since 2007 for the construction materials division.*
- *Knife River Corporation received the largest road construction contract in its history, a $55 million North Dakota highway bypass project.*
- *Had record sales and rentals for specialty power line equipment and materials for the third consecutive year.*
- *Engineering News-Record ranked MDU Construction Services Group No. 11 out of the Top 600 specialty contractors in the United States.*

2013 Key Statistics

Revenues (millions)	
Construction materials	$1,712.1
Construction services	$1,039.8
Earnings (millions)	
Construction materials	$50.9
Construction services	$52.2
Construction materials sales (millions)	
Aggregates (tons)	24.7
Asphalt (tons)	6.2
Ready-mix concrete (cubic yards)	3.2
Construction materials aggregate reserves (billion tons)	1.1
Corporate earnings contribution	
Construction materials	18%
Construction services	18%

A Look Ahead

- *Combined construction backlog is about 25 percent higher for 2014 than it was at the start of 2013.*
- *Expecting momentum to continue to grow in the construction industry with strong national indicators and trends.*
- *Continuing to focus on increasing margins and cash flow while maximizing the value of the company's 1.1 billion tons of strategically located aggregate reserves.*
- *Building on effective use of technology in construction services to improve planning, design-assist, prefabrication and integrated project delivery.*

Notes:
- *The earnings and earnings contributions noted on this page reflect adjusted earnings and exclude the Other category and intercompany eliminations. For GAAP earnings and for a discussion of adjustments to GAAP earnings, see page 1.*
- *Consolidated revenues reflect intersegment eliminations of $146.4 million.*
- *The Other category includes revenues of $9.6 million.*

Highlights

Years Ended December 31,	2013	2012	Increase/(Decrease) Amount
		(In millions, where applicable)	
Operating revenues	$4,462.4	$4,075.4	$ 387.0
Operating income	$ 492.9	$ 19.2	$ 473.7
Earnings (loss) on common stock	$ 278.2	$ (1.4)	$ 279.6
Adjustments net of tax:			
Discontinued operations	.3	(13.6)	13.9
Unrealized commodity derivatives loss	3.9	.4	3.5
Natural gas gathering asset impairment	9.0	1.7	7.3
Net benefit related to natural gas gathering operations litigation	(1.5)	(15.0)	13.5
Write-downs of oil and natural gas properties	–	246.8	(246.8)
Adjusted earnings	$ 289.9	$ 218.9	$ 71.0
Earnings (loss) per share	$ 1.47	$ (.01)	$ 1.48
Adjusted earnings per share	$ 1.53	$ 1.16	$ .37
Dividends declared per common share	$ .6950	$ .6750	$ .02
Weighted average common shares outstanding – diluted	189.7	188.8	.9
Total assets	$7,061.3	$6,682.5	$ 378.8
Total equity	$2,855.9	$2,648.2	$ 207.7
Total debt	$1,866.1	$1,773.2	$ 92.9
Capitalization ratios:			
Total equity	60.5%	59.9%	
Total debt	39.5	40.1	
	100.0%	100.0%	
Price/earnings ratio*	20.0x	18.3x	
Book value per common share	$ 15.01	$ 13.95	
Market value as a percent of book value	203.5%	152.3%	
Employees	9,133	8,629	

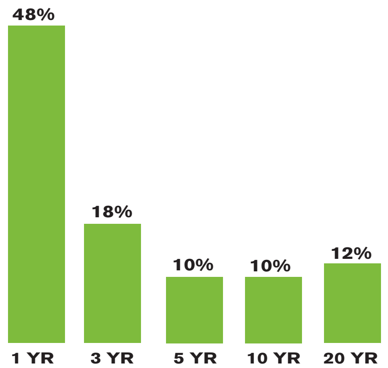
*Represents 12 months ended. Based on adjusted earnings.

Note: The company, in addition to presenting its earnings information in conformity with Generally Accepted Accounting Principles, has provided non-GAAP earnings data that reflect adjustments to exclude: write-downs of oil and natural gas properties of $246.8 million after tax in 2012, net benefits related to natural gas gathering operations litigation of $1.5 million after tax in 2013 and $15.0 million after tax in 2012, natural gas gathering asset impairments of $9.0 million after tax in 2013 and $1.7 million after tax in 2012 and an unrealized commodity derivatives loss of $3.9 million after tax in 2013 and $400,000 after tax in 2012. 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.

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 2013 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

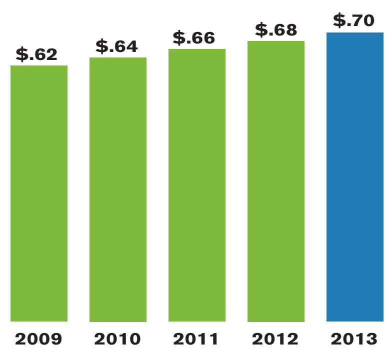
(as of December 31, 2013)



Dividends

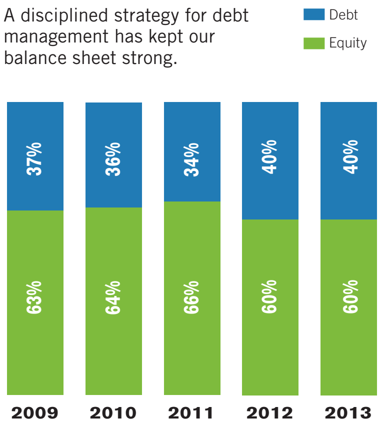
(per common share)

We have paid dividends uninterrupted for 76 years.



Capitalization Ratios

A disciplined strategy for debt management has kept our balance sheet strong.



Report to Stockholders

The past year was a success by almost any measure. We restored earnings to their highest level since 2008 and provided stockholders with a strong return on their investment. Our employees executed our business plan effectively and efficiently. And perhaps most important, our capital investment program is showing results, while also continuing to build the foundation for sustainable long-term growth.

Consolidated adjusted earnings in 2013 increased 32 percent to $289.9 million, or $1.53 per share, compared to $218.9 million, or $1.16 per share in 2012. Consolidated GAAP earnings were $278.2 million, or $1.47 per share, compared to a loss of $1.4 million, or 1 cent per share, in 2012.

The market has recognized our performance with a common stock price that is trading at its highest level since the fall of 2008, contributing to a total stockholder return in 2013 of 48 percent. That return also includes the common stock dividend, which the board of directors increased in November. This was the 23rd consecutive year that we have increased the dividend, an accomplishment matched by only about 100 publicly traded companies in North America. This continues our long-standing commitment to stockholders. In fact, MDU Resources has paid dividends for 76 consecutive years, dating back to 1937.

As we begin our 90th year in 2014, we consider these results in the same manner that we view our company's history. We take pride in our accomplishments, but at the same time remain squarely focused on achieving even more in the future. We certainly are happy with the results of last year, but we also look at 2013 as a stepping-stone in our plan to build sustainable long-term growth. In that effort we have invested $1.7 billion in capital expenditures over the last two years, and this year we plan to spend approximately $960 million.

We are proud to share with you the results of 2013, as well as the strategies that we believe will lead to continued growth for stockholders.

Fidelity Hits Production Goal

A large portion of our capital investment has been directed at Fidelity Exploration & Production, our oil and natural gas production business, which has successfully transitioned from a natural gas-centric business to a more balanced portfolio that can capitalize on higher-return oil production. Fidelity hit its 2013 production growth target with a 30 percent increase in oil production, despite bitterly cold December temperatures that impacted operations in North Dakota. Over the last two years, oil production has grown by 77 percent.

There are two principal drivers of this growth. The first is in our own backyard – Bakken oil fields that have propelled North Dakota to become our country's second-largest oil-producing state, behind only Texas. Nearly 60 percent of Fidelity's 4.8 million net barrels of oil produced in 2013 came from the Bakken, where we have around 130 operated wells on approximately 125,000 net acres of leaseholds. Our Bakken oil production increased by 36 percent last year.

Fidelity also is ramping up production in the Paradox Basin in Utah, where it has approximately 130,000 net acres with an option to earn another 20,000. Although in an earlier stage of development than the Bakken, 2013 production from the Paradox Basin increased by 221 percent to 831,000 barrels.

Our early results demonstrate the potential of the Paradox Basin play.

Harry J. Pearce
Chairman of the Board

David L. Goodin
President and Chief Executive Officer

Fidelity's Cane Creek 12-1 well was among the best onshore U.S. oil wells drilled in 2012; it produced more than 480,000 barrels in its first year, and 15 months after completion it continues to maintain consistently high flow rates. A subsequent well, Cane Creek 36-1, is producing comparable results, flowing at about 930 barrels per day since completion last October. A gathering line and processing plant are being constructed to eliminate the need to flare the natural gas that is produced along with the oil.

This year Fidelity will again concentrate the largest share of its drilling program in the Bakken and Paradox Basin. It plans to operate two rigs in each play.

Large Market Demand for Diesel Refinery

The Bakken's prolific oil production also offers opportunities for our pipeline and energy services business, WBI Energy. Foremost among these is Dakota Prairie Refining, which we are building in western North Dakota in partnership with Calumet Specialty Products Partners. This is the first greenfield refinery built in the U.S. since 1976. It will have the capacity to process 20,000 barrels per day of Bakken crude into about 7,000 barrels per day of diesel fuel, along with byproducts such as naphtha and atmospheric tower bottoms.

All of our businesses are participating in this project. WBI Energy is co-owner and will provide natural gas; Fidelity will provide crude oil, either directly or in kind; our utility business will provide electricity; and our construction businesses are providing some of the materials and services to build the facility. We expect to finish the $350 million refinery by the end of this year. The facility currently is about 40 percent complete.

The diesel will be sold into an expanding local market that already is vastly under-supplied. Driven by oil industry and agricultural uses, North Dakota diesel consumption has increased about 60 percent in the past five years to more than 55,000 barrels per day. Consumption is expected to grow to 75,000 barrels per day by 2025. The state's lone refinery produces just 22,000 barrels per day; the remaining supply must be imported from out-of-state sources.

WBI Energy also plans to build a 375-mile pipeline across northern North Dakota to increase takeaway capacity for the large amount of natural gas that accompanies Bakken oil production. The pipeline would have an initial capacity of 400 million cubic feet per day, and would provide producers with access to a number of markets through interconnecting pipelines. At a cost of approximately $650 million, this would be the largest project in the corporation's history.

The company benefitted from its first full year of ownership of Pronghorn midstream assets in western North Dakota. We purchased a 50 percent interest in this new facility in 2012, and operations have been steadily growing since then. It includes a natural gas processing plant and related facilities, as well as an oil storage terminal.

Utility Business has Record Year

Our utility business had record earnings that were 21 percent higher than 2012 as a result of both weather and good customer growth. The year began and ended with temperatures that were significantly below normal, ranging up to 25 percent colder from Idaho through the Plains states. That also contributed to a 15 percent increase in natural gas sales.

Our customer base increased by just over 2 percent, with even higher growth concentrated in communities across the Bakken region. Our four utilities now serve more than 1 million customers, stretching from western Minnesota to Washington and Oregon.

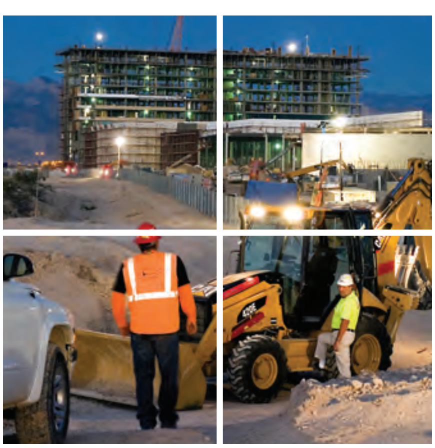
The utility business is investing at record levels in infrastructure improvements to ensure they can support this growth with safe, reliable energy service. The $270 million spent in 2013 and $300 million planned in 2014 are part of a five-year capital spending program totaling about $1.3 billion. This includes a $77 million, 88-megawatt natural gas-fueled generating facility that is expected to go into service in the third quarter of this year, significant environmental upgrades

at the Big Stone and Lewis & Clark generating plants, and work to upgrade and strengthen the electric transmission and distribution system. Similar work is planned this year for the natural gas systems in Idaho, Oregon and Washington. In addition, we are building a $60 million, 30-mile pipeline that will provide natural gas service to the federal government's nuclear waste remediation site in Hanford, Washington. It is expected to be ready for service in 2015.

We are proud that our utility employees have successfully met the challenges of this growth without sacrificing their focus on customer service. Cascade Natural Gas and Intermountain Gas tied for first place, with the highest ranking among midsize natural gas utilities in the West Region, in a nationally recognized residential customer satisfaction study conducted in 2013. It was the fourth straight year that Intermountain Gas has earned the top spot.

Construction Businesses Continue Strong Growth

Our construction businesses increased their combined earnings by about 46 percent to their highest level since 2007. Their combined backlog at year-end stood at $915 million compared with $731 million a year earlier. While segments of their markets remain weak, overall we believe we are experiencing an industry recovery that can be sustained.



The construction materials business, Knife River Corporation, increased earnings 57 percent. It is operating extremely efficiently. Knife River benefited from favorable fall weather that extended the construction season and allowed it to get a good start on a $55 million highway bypass project in western North Dakota. It is the largest road construction contract the company has been awarded.

The construction services business had record earnings in 2013, with higher earnings in every business line. Our construction services business has built on its operational excellence practices by further using technology for planning and executing construction, manufacturing, assembly and quality activities.

Our construction companies' success is a testament to the hard work and skill of our employees who work in these businesses.

Thanks to Those Who Make It Possible

We want to recognize and thank all of our employees, who number more than 11,000 during peak construction season. A great deal of the company's success is due to the exemplary way in which they operate our businesses with integrity and an outstanding commitment to customers.

Our employees also are extremely committed to safety, and we perform better than industry averages in most areas. But there is always room for improvement, so we remain focused on our goal of zero accidents or injuries. We thank our employees for their continuing efforts to work safely every day.

We also want to thank Tom Knudson, who has decided not to stand for re-election to the board of directors this year. We are grateful for Tom's counsel and contributions during his years of service.

Finally, thank you for your investment in MDU Resources. We appreciate the confidence in our business that is reflected in your continued stock ownership. Please be assured that while we are pleased with the past year's results, we are committed to building even more robust and sustainable growth.

Harry J. Pearce
Chairman of the Board

David L. Goodin
President and Chief Executive Officer

February 21, 2014

Board of Directors

Harry J. Pearce
71 (17)
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: Multinational business management, leadership, finance, engineering and law

David L. Goodin
52 (1)
Bismarck, North Dakota

President and chief executive officer of MDU Resources

Formerly president and chief executive officer of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

Thomas Everist
64 (19)
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
60 (9)
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, construction and business management

Mark A. Hellerstein
61 (1)
Denver, Colorado

Retired, formerly chairman, president and chief executive officer of St. Mary Land & Exploration Co.; a former director of Transocean Inc.

Expertise: Oil and natural gas industry, business management, accounting and finance

A. Bart Holaday
71 (6)
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
64 (13)
Dickinson, North Dakota

Chairman, president and chief executive officer 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
67 (6)
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

William E. McCracken
71 (1)
Warren, New Jersey

Retired, formerly chairman and chief executive officer of CA Technologies; previously held executive positions with IBM Corp.; a former director of ICON Office Solutions Inc.

Expertise: Multinational business management, corporate governance and technology

Patricia L. Moss
60 (11)
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, business development and human resources

J. Kent Wells
57 (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
59 (11)
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: Public utilities, accounting and finance

Audit Committee
Dennis W. Johnson, Chairman
Mark A. Hellerstein
A. Bart Holaday
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
William E. McCracken
Patricia L. Moss

Numbers indicate age and years of service ( ) on the MDU Resources Board of Directors as of December 31, 2013.

Corporate Management

David L. Goodin
52 (31)

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 Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

David C. Barney
58 (28)

President and Chief Executive Officer of Knife River Corporation

Formerly held executive and management positions with Knife River

Steven L. Bietz
55 (33)

President and Chief Executive Officer of WBI Holdings, Inc.

Formerly held executive and management positions with WBI Holdings

Mark A. Del Vecchio
54 (11)

Vice President of Human Resources of MDU Resources

Formerly director of compensation and executive programs of MDU Resources

Dennis L. Haider
61 (36)

Executive Vice President of Business Development of MDU Resources

Formerly executive vice president of marketing, gas supply and business development of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

K. Frank Morehouse
55 (13)

President and Chief Executive Officer of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

Formerly executive vice president and general manager of Cascade Natural Gas and Intermountain Gas

Cynthia J. Norland
59 (30)

Vice President of Administration of MDU Resources

Formerly associate general counsel of MDU Resources

Paul K. Sandness
59 (34)

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

Doran N. Schwartz
44 (9)

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

Jeffrey S. Thiede
51 (10)

President and Chief Executive Officer of MDU Construction Services Group, Inc.

Formerly held executive and management positions with MDU Construction Services Group

J. Kent Wells
57 (3)

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

Other Corporate and Senior Company Officers

William R. Connors, 52 (10)
Vice President of Renewable Resources of MDU Resources

Nicole A. Kivisto, 40 (19)
Vice President, Controller and Chief Accounting Officer of MDU Resources

Douglass A. Mahowald, 64 (32)
Treasurer and Assistant Secretary of MDU Resources

John P. Stumpf, 54 (22)
Vice President of Strategic Planning of MDU Resources

Management Changes

David C. Barney was named president and chief executive officer of Knife River Corporation, effective April 30, 2013.

Jeffrey S. Thiede was named president and chief executive officer of MDU Construction Services Group, Inc., effective April 30, 2013.

Dennis L. Haider was named executive vice president of business development of MDU Resources, effective June 1, 2013.

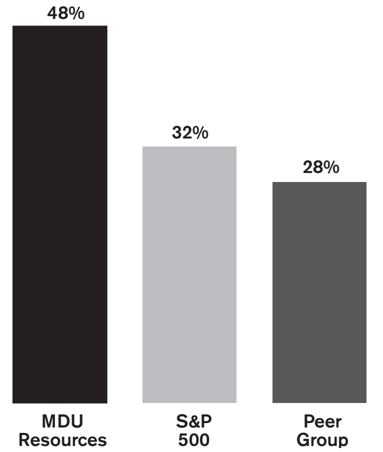
Nathan W. Ring was named vice president, controller and chief accounting officer of MDU Resources, effective January 3, 2014, to replace Nicole A. Kivisto, who has accepted an executive position with a division of the corporation.

Numbers indicate age and years of service ( ) as of December 31, 2013.

Stockholder Return Comparison

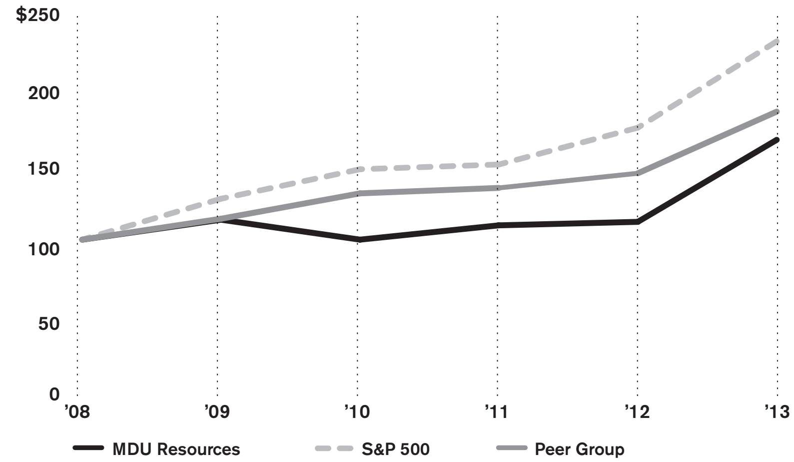
Comparison of One-Year Total Stockholder Return

(as of December 31, 2013)



Comparison of Five-Year Total Stockholder Return (in dollars)

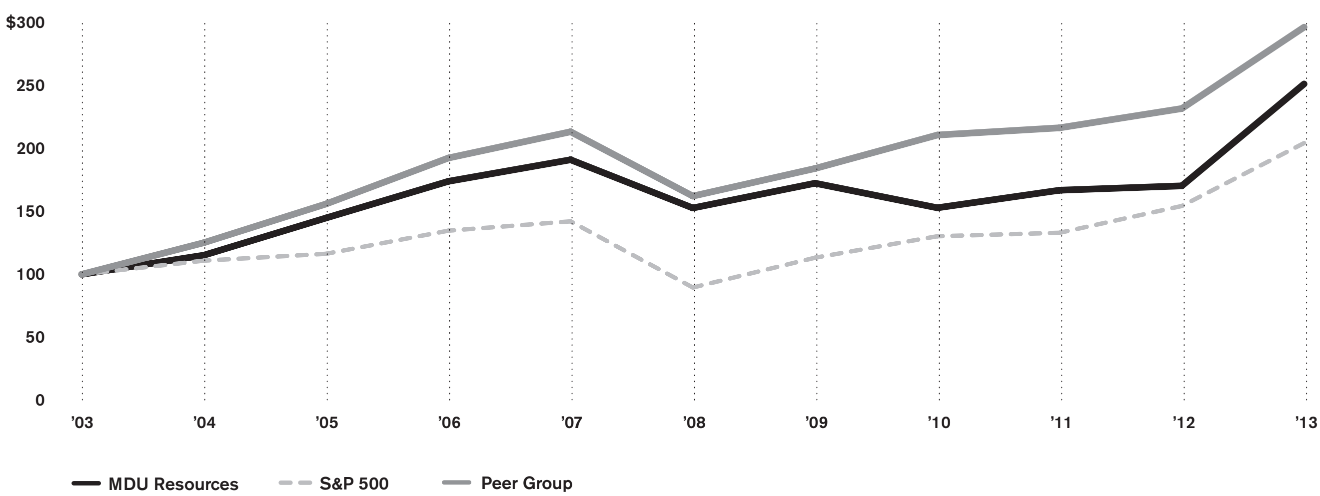
$100 invested December 31, 2008, in MDU Resources was worth $164.53 at year-end 2013.



	2008	2009	2010	2011	2012	2013
MDU Resources Group, Inc.	$100.00	$112.89	$100.09	$109.25	$111.51	$164.53
S&P 500 Index	100.00	126.46	145.51	148.59	172.37	228.19
Peer Group	100.00	113.53	129.92	133.45	142.90	182.76

Comparison of 10-Year Total Stockholder Return (in dollars)

$100 invested December 31, 2003, in MDU Resources was worth $251.27 at year-end 2013.



	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
MDU Resources Group, Inc.	$100.00	$115.21	$144.81	$173.91	$191.05	$152.72	$172.41	$152.87	$166.85	$170.31	$251.27
S&P 500 Index	100.00	110.88	116.33	134.70	142.10	89.53	113.22	130.27	133.03	154.32	204.30
Peer Group	100.00	125.15	155.95	192.44	213.30	162.17	184.12	210.70	216.42	231.75	296.38

Stockholder Return Comparison

Data is indexed to December 31, 2012, for the one-year total stockholder return comparison, December 31, 2008, for the five-year total stockholder return comparison and December 31, 2003, 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., 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 2013, Berry Petroleum 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, 2013

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, 2013: $4,892,599,006.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 14, 2014: 189,370,016 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of the registrant's 2014 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

Contents

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
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	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Black Hills Power	Black Hills Power, Inc.
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
BOPD	Barrels of oil per day
Brazilian Transmission Lines	Company's investment in the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE were sold in the fourth quarter of 2010 and portions of the ownership interest in ECTE were sold in the third quarters of 2013 and 2012 and the fourth quarters of 2011 and 2010)
Btu	British thermal unit
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CCU	Cane Creek Unit
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
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
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant being built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company jointly owned by WBI Energy and Calumet
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. (2.5 percent ownership interest at December 31, 2013, 2.5, 2.5, 2.5 and 14.99 percent ownership interests were sold in the third quarters of 2013 and 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
GVTC	Generation Verification Test Capacity
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
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

K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
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
MISO	Midcontinent Independent 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
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
Proxy Statement	Company's 2014 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
VIE	Variable interest entity
WBI Energy	WBI Energy, Inc., an indirect wholly owned subsidiary of WBI Holdings
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
ZRC	Zonal resource credit – a MW of demand equivalent assigned to generators by MISO for meeting system reliability requirements

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 investment in ECTE is reflected in the Other category. For additional information, see Item 8 – Note 4.

As of December 31, 2013, the Company had 9,133 employees with 157 employed at MDU Resources Group, Inc., 1,010 at Montana-Dakota, 34 at Great Plains, 302 at Cascade, 219 at Intermountain, 583 at WBI Holdings, 3,071 at Knife River and 3,757 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, 2013.

At Montana-Dakota and WBI Energy Transmission, 350 and 77 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, 173 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, 2016.

Knife River operates under 43 labor contracts that represent approximately 520 of its construction materials employees. Knife River is in negotiations on 7 of its labor contracts.

MDU Construction Services has 176 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 the Bremerton Gasworks Superfund Site.

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 and 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 134,000 residential, commercial, industrial and municipal customers in 177 communities and adjacent rural areas as of December 31, 2013. 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 52 transmission and 269 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, 2013, Montana-Dakota's net electric plant investment was $812.9 million.

The percentage of Montana-Dakota's 2013 retail electric utility operating revenues by jurisdiction is as follows: North Dakota – 62 percent; Montana – 22 percent; Wyoming – 10 percent; and South Dakota – 6 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 MISO, Montana-Dakota has access to wholesale energy, ancillary services and capacity markets for its integrated system. MISO is a regional transmission organization responsible for operational control of the transmission systems of its members. MISO provides security center operations, tariff administration and operates day-ahead and real-time energy markets, ancillary services and capacity markets. As a member of MISO, Montana-Dakota's generation is sold into the MISO 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, Williston and Watford City; eastern Montana, including Sidney, 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 2018 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 ZRCs of 452.5 in 2013. ZRCs are a MW of demand equivalent measure and are allocated to individual generators to meet supply obligations within MISO. For 2013, Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 583.5. Montana-Dakota's peak demand supply obligation, including firm purchase power contracts, within MISO was 508.3 ZRCs for 2013. 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) 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 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. On October 25, 2013, Montana-Dakota entered into a power purchase agreement with Thunder Spirit Wind, LLC, a subsidiary of Wind Works Power Corp., for approximately 107 MW of installed capacity of wind turbine generators to be located in southwest North Dakota for a 25-year period effective on the commercial operation date of the facility. The project is expected to begin commercial operation in the fourth quarter of 2015. The generation will interconnect at Montana-Dakota's substation near Hettinger, North Dakota. Energy also will be purchased as needed, or if more economical, from the MISO market. In 2013, Montana-Dakota purchased approximately 29 percent of its net kWh needs for its interconnected system through the MISO market.

Montana-Dakota is constructing an 88-MW simple-cycle natural gas turbine and associated facilities, with an estimated project cost of $77 million and a projected in-service date in the third quarter 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 Compatibility 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)	2013 ZRCs (a)	2013 Net Generation (kWh in thousands)
Interconnected System:				
North Dakota:				
Coyote (b)	Steam	103,647	101.7	666,431
Heskett	Steam	86,000	85.4	444,867
Glen Ullin	Heat Recovery	7,500	4.3	38,053
Cedar Hills	Wind	19,500	4.5	54,805
Diesel Units	Oil	5,475	5.6	6
South Dakota:				
Big Stone (b)	Steam	94,111	101.3	623,380
Montana:				
Lewis & Clark	Steam	44,000	52.1	298,969
Glendive	Combustion Turbine	75,522	72.9	1,782
Miles City	Combustion Turbine	23,150	19.5	–
Diamond Willow	Wind	30,000	5.2	93,175
		488,905	452.5	2,221,468
Sheridan System:				
Wyoming:				
Wygen III (b)	Steam	28,000	N/A	208,533
		516,905	452.5	2,430,001

(a) Interconnected system only. MISO requires generators to obtain their summer capability through the GVTC. The GVTC is then converted to ZRCs by applying each generator's forced outage factor against its GVTC. Wind generator's ZRCs are calculated based on a wind capacity study performed annually by MISO. ZRCs are used to meet supply obligations within MISO.

(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 Station 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.

Montana-Dakota has 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.

Montana-Dakota has coal supply agreements, which meet a portion of the Big Stone Station's fuel requirements, for the purchase of 1.0 million tons in 2014, 1.0 million tons in 2015 and 500,000 tons in 2016 from Peabody Coalsales, LLC, and 500,000 tons in 2014 from Westmoreland 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,	**2013**	2012	2011
Average cost of coal per MMBtu	**$ 1.73**	$ 1.69	$ 1.62
Average cost of coal per ton	**$25.32**	$24.77	$23.38

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-2016. 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 MISO 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 those 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. The Title V Operating Permit renewal application for Coyote Station was submitted to the North Dakota Department of Health in March 2013 and the Title V Operating Permit renewal application for Big Stone Station was submitted to the South Dakota Department of Environment and Natural Resources in November 2013.

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 $32.7 million of environmental capital expenditures in 2013, largely for the installation of a BART air quality control system at the Big Stone Station. Capital expenditures are estimated to be $47 million, $46 million and $8 million in 2014, 2015 and 2016, respectively, to maintain environmental compliance as new emission controls are required, including the installation of a BART air quality control system, as discussed above. Projects for 2014 through 2016 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 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 876,000 residential, commercial and industrial customers in 334 communities and adjacent rural areas across eight states as of December 31, 2013, and provide natural gas transportation services to certain customers on their systems. These services are provided through distribution systems aggregating approximately 18,500 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, 2013, the natural gas distribution operations' net natural gas distribution plant investment was $1.1 billion.

The percentage of the natural gas distribution operations' 2013 natural gas utility operating sales revenues by jurisdiction is as follows: Idaho – 34 percent; Washington – 24 percent; North Dakota – 14 percent; Oregon – 8 percent; Montana – 8 percent; South Dakota – 6 percent; Minnesota – 4 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, Watford City, Minot and Jamestown; central and eastern Oregon, including Bend, Pendleton, Ontario and Baker City; western and north-central South Dakota, including Rapid City, Pierre, Spearfish and Mobridge; western, southeastern and south-central Washington, including Bellingham, Bremerton, Longview, Aberdeen, Wenatchee/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.

On March 13, 2013, the OPUC approved an extension of Cascade's decoupling mechanism until December 31, 2015. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

For additional 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 locations 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.

The natural gas distribution operations did not incur any material environmental expenditures in 2013. 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 2016.

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. Montana-Dakota is investigating a former manufactured gas plant in Montana. Montana-Dakota will seek recovery through the MTPSC in its natural gas rates charged to customers for any remediation costs incurred for this site. None of the remaining former manufactured gas plant sites of Montana-Dakota or Great Plains are being actively investigated. 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 three manufactured gas plants in Washington and Oregon. 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 owns and operates both regulated and nonregulated businesses. The regulated business of this segment, WBI Energy Transmission, 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. Its system is strategically located near five natural gas producing basins, making natural gas supplies available to its 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. 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, and at December 31, 2013, its net plant investment was $337.6 million.

The nonregulated business of this segment, owns and operates gathering facilities in Colorado, Montana and Wyoming. It also owns a 50 percent undivided interest in the Pronghorn 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 1,600 miles of operated field gathering lines, some of which interconnect with WBI Energy's regulated pipeline system. The nonregulated business 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.

WBI Energy, in conjunction with Calumet, formed Dakota Prairie Refining, to develop, build and operate Dakota Prairie Refinery. Construction began on the facility in late March 2013 and, when complete, it will process Bakken crude oil into diesel, which will be marketed within the Bakken region. Total project costs are estimated to be approximately $350 million, with a projected in-service date in late 2014.

This segment also includes an energy services business which 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 Fidelity. Certain of the services are provided based on contracts that call for a determinable quantity of natural gas. At December 31, 2013, it has commitments to deliver fixed and determinable amounts of natural gas under these contracts of 1.9 MMdk in 2014 and the commitments to deliver natural gas for years subsequent to 2014 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 Supply, System Demand and Competition 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. These storage facilities enable customers to purchase natural gas at more uniform daily volumes throughout the year and meet winter peak requirements.

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 its system near five natural gas producing basins and the availability of underground storage and gathering services, along with interconnections with other pipelines, serve to enhance its 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 2013 represented 45 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.

The nonregulated business competes with several midstream companies for existing customers, for the expansion of its systems and for the installation of new systems. Its 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.

Regulatory Matters For additional information on regulatory matters, see Item 8 – Note 18.

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 and its subsidiaries 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 2013 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2016.

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.

For information regarding exploration and production litigation, see Item 8 – Note 19.

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 50,000 net acres in Stark County, North Dakota, and approximately 59,000 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 130,000 net acres located in Grand and San Juan Counties, Utah, targeting oil, including its recent acquisition of 35,000 net acres of leaseholds and has an option to earn another 20,000 acres.
- Big Horn Basin – These interests include approximately 21,000 net acres in Wyoming, targeting oil and NGL.
- Green River Basin – These properties were primarily natural gas targets in Wyoming and were sold at the end of 2013.
- Baker Field – Long-held natural gas properties in which Fidelity holds approximately 98,000 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 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 Texas – Fidelity holds approximately 9,000 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 2013 was as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total
Rocky Mountain	4,481	250	19,461	7,975	78%
Mid-Continent/Gulf States	334	531	8,547	2,289	22
Total	4,815	781	28,008	10,264	100%

Note: Bakken-Mountrail County represents 43% 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, 2013.

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.

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, 2013, were as follows:

	Gross*	Net**
Productive wells:		
Oil	899	171
Natural gas	2,006	1,541
Total	2,905	1,712
Developed acreage (000's)	581	347
Undeveloped acreage set to expire in the years (000's):		
2014	87	63
2015	130	81
2016	22	16
Thereafter	563	277
Total undeveloped acreage	802	437

* 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, 2013, Fidelity has commitments to deliver fixed and determinable amounts of oil under contracts of 452,500 Bbls in 2014 and the commitments to deliver oil for years subsequent to 2014 are immaterial. Fidelity does not have any material delivery commitments to deliver fixed and determinable amounts of natural gas at December 31, 2013.

Exploratory and Development Wells The following table reflects activities related to Fidelity's oil and natural gas wells drilled and/or tested during 2013, 2012 and 2011:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2013	**3**	**2**	**5**	**35**	**3**	**38**	**43**
2012	24	3	27	39	1	40	67
2011	4	–	4	48	–	48	52

At December 31, 2013, there were 11 gross (5 net) wells in the process of drilling or under evaluation, all of which were development 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 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 2013 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2016.

Proved Reserve Information Estimates of proved oil, NGL and natural gas 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 mathematics with a technical minor in petroleum engineering, has 26 years of experience in petroleum engineering and reserve estimation, and is a member of the Society of Petroleum Engineers.
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, 2013. 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, 2013, are as follows:

Region	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)	Percent of Total	PV-10 Value* (in millions)
Rocky Mountain	38,788	2,442	128,124	62,584	78%	$1,159.3
Mid-Continent/Gulf States	2,231	4,160	70,321	18,111	22	175.7
Total proved reserves	41,019	6,602	198,445	80,695	100%	1,335.0
Discounted future income taxes						321.0
Standardized measure of discounted future net cash flows relating to proved reserves						$1,014.0

* 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 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 $456 million in backlog at December 31, 2013, compared to $406 million at December 31, 2012. The Company anticipates that a significant amount of the current backlog will be completed during 2014.

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 Aggregate 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 2011 through 2013. 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, 2013, and sales for the years ended December 31, 2013, 2012 and 2011:

	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	**2013**	2012	2011	(000's tons)	Expiration	(years)
Anchorage, AK	–	–	1	–	**1,074**	110	137	18,880	N/A	43
Hawaii	–	6	–	–	**1,672**	1,678	1,527	57,333	2017-2064	35
Northern CA	–	–	9	1	**1,525**	1,203	1,552	45,570	2018	32
Southern CA	–	2	–	–	**241**	784	1,134	92,110	2035	Over 100
Portland, OR	1	3	5	3	**3,343**	2,698	3,106	231,734	2014-2055	76
Eugene, OR	3	4	4	1	**825**	847	884	168,392	2016-2046	Over 100
Central OR/WA/ID	1	2	5	4	**1,045**	1,131	851	123,613	2015-2077	Over 100
Southwest OR	5	4	11	5	**1,465**	1,613	1,604	96,768	2014-2053	62
Central MT	–	–	1	2	**1,236**	1,200	758	28,213	2017-2027	26
Northwest MT	–	–	7	2	**1,242**	1,011	1,370	65,993	2016-2020	55
Wyoming	–	–	1	1	**983**	428	461	11,571	2019	19
Central MN	–	1	37	24	**1,578**	1,714	1,520	73,429	2014-2028	46
Northern MN	2	–	16	5	**349**	195	355	26,782	2015-2017	89
ND/SD	–	–	3	19	**1,862**	1,711	1,727	30,899	2014-2031	17
Iowa	–	–	–	–	**–**	305	249	–	–	–
Texas	1	1	1	–	**672**	692	1,182	12,089	2022	14
Sales from other sources					**5,601**	5,965	6,319			
					24,713	23,285	24,736	1,083,376		

The 1.1 billion tons of estimated aggregate reserves at December 31, 2013, are comprised of 494 million tons that are owned and 589 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 28 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2011 through 2013 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 68 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:

	2013	2012	2011
		(000's of tons)	
Aggregate reserves:			
Beginning of year	**1,088,236**	1,088,833	1,107,396
Acquisitions	**22,682**	950	1,200
Sales volumes*	**(19,112)**	(17,320)	(18,417)
Other**	**(8,430)**	15,773	(1,346)
End of year	**1,083,376**	1,088,236	1,088,833

* 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 2013 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 2016.

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.

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, 2013, MDU Construction Services owned or leased facilities in 16 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, 2013, was approximately $459 million compared to $325 million at December 31, 2012. MDU Construction Services expects to complete a significant amount of this backlog during 2014. 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 2013 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2016.

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/or operation of power generation facilities and Dakota Prairie Refinery may involve unanticipated events 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 and Dakota Prairie Refinery involve many risks, which may include: delays; breakdown or failure of equipment; inability to obtain required governmental permits and approvals; inability to complete financing; inability to negotiate acceptable equipment acquisition, construction, fuel and crude oil supply, off-take, transmission, transportation or other material agreements; changes in markets and market prices for power, crude oil and refined products; 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 rate changes, governmental budget constraints and the ongoing threat of terrorism can create volatility in the financial markets. Unfavorable economic conditions can negatively affect the level of public and private expenditures on projects and the timing of these projects which, in turn, can negatively affect 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 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 negatively affect the funding available for infrastructure spending. This 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 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, cause delays as a result of litigation and administrative proceedings, and create compliance, remediation, containment, monitoring and reporting obligations, particularly with regard to laws relating to electric generation operations and oil and natural gas development and processing. 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 controls, 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 Standards rules that will require reductions in mercury and other 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 additional particulate matter control is required to control non-mercury metal emissions at the Lewis & Clark Station near Sidney, Montana. On October 9, 2013, Montana-Dakota received an order from the NDPSC approving Montana-Dakota's request for advance determination of prudence to install a baghouse at Lewis & Clark Station. 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 on 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 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. This new rule's impacts on Fidelity, WBI Energy Transmission and WBI Energy Midstream 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. On June 25, 2013, President Obama released his Climate Action Plan for the U.S. in which he stated his goal to reduce GHG emissions "in the range of 17 percent" below 2005 levels by 2020. The president issued a memorandum to the EPA on the same day, instructing the EPA to re-propose the GHG NSPS rule for new electric generation units. The EPA released the re-proposed rule on January 8, 2014, in the Federal Register, which takes the place of the rule proposed in 2012 for new electric generation units that the EPA did not finalize. This rule applies to new fossil fuel-fired electric generation units, including coal-fired units, natural gas-fired combined-cycle units and natural gas-fired simple cycle peaking units. The EPA's 1,100 pounds of carbon dioxide per MW hour emissions standard for coal-fired units does not allow for any new coal-fired electric generation to be constructed unless carbon dioxide is 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 president also directed the EPA to develop a GHG NSPS standard for existing fossil fuel-fired electric generation units by June 1, 2014, with finalization by June 1, 2015. The president did not specify a GHG standard or the format of the standard.

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's existing electric generating facilities are expected to be subject to GHG laws or regulations within the next few years through a GHG NSPS 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. 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. The pipeline and energy services business 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, actions taken by the plans' other participating employers, 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 2013 and 2012 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Declared Per Share
2013			
First quarter	**$25.00**	**$21.50**	**$.1725**
Second quarter	**27.14**	**23.37**	**.1725**
Third quarter	**30.21**	**25.94**	**.1725**
Fourth quarter	**30.97**	**27.53**	**.1775**
			$.6950
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

As of December 31, 2013, the Company's common stock was held by approximately 13,900 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, 2013	–			
November 1 through November 30, 2013	33,027	$30.53		
December 1 through December 31, 2013	3,686	29.83		
Total	36,713			

(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.

FORM 10-K

FORM 10-K

Item 6. Selected Financial Data

	2013	2012 (a)	2011	2010	2009 (b)	2008 (c)
Selected Financial Data						
Operating revenues (000's):						
Electric	**$ 257,260**	$ 236,895	$ 225,468	$ 211,544	$ 196,171	$ 208,326
Natural gas distribution	**851,945**	754,848	907,400	892,708	1,072,776	1,036,109
Pipeline and energy services	**202,068**	193,157	278,343	329,809	307,827	532,153
Exploration and production	**536,023**	448,617	453,586	434,354	439,655	712,279
Construction materials and contracting	**1,712,137**	1,617,425	1,510,010	1,445,148	1,515,122	1,640,683
Construction services	**1,039,839**	938,558	854,389	789,100	819,064	1,257,319
Other	**9,620**	10,370	11,446	7,727	9,487	10,501
Intersegment eliminations	**(146,488)**	(124,439)	(190,150)	(200,695)	(183,601)	(394,092)
	$4,462,404	$4,075,431	$4,050,492	$3,909,695	$4,176,501	$5,003,278
Operating income (loss) (000's):						
Electric	**$ 54,274**	$ 49,852	$ 49,096	$ 48,296	$ 36,709	$ 35,415
Natural gas distribution	**78,829**	67,579	82,856	75,697	76,899	76,887
Pipeline and energy services	**20,046**	49,139	45,365	46,310	69,388	49,560
Exploration and production	**161,402**	(276,642)	133,790	143,169	(473,399)	202,954
Construction materials and contracting	**93,629**	57,864	51,092	63,045	93,270	62,849
Construction services	**85,246**	66,531	39,144	33,352	44,255	81,485
Other	**6,649**	4,884	5,024	858	(219)	2,887
Intersegment eliminations	**(7,176)**	–	–	–	–	–
	$ 492,899	$ 19,207	$ 406,367	$ 410,727	$ (153,097)	$ 512,037
Earnings (loss) on common stock (000's):						
Electric	**$ 34,837**	$ 30,634	$ 29,258	$ 28,908	$ 24,099	$ 18,755
Natural gas distribution	**37,656**	29,409	38,398	36,944	30,796	34,774
Pipeline and energy services	**7,629**	26,588	23,082	23,208	37,845	26,367
Exploration and production	**94,450**	(177,283)	80,282	85,638	(296,730)	122,326
Construction materials and contracting	**50,946**	32,420	26,430	29,609	47,085	30,172
Construction services	**52,213**	38,429	21,627	17,982	25,589	49,782
Other	**5,136**	4,797	6,190	21,046	7,357	10,812
Intersegment eliminations	**(4,307)**	–	–	–	–	–
Earnings (loss) on common stock before income (loss) from discontinued operations	**278,560**	(15,006)	225,267	243,335	(123,959)	292,988
Income (loss) from discontinued operations, net of tax	**(312)**	13,567	(12,926)	(3,361)	–	–
	$ 278,248	$ (1,439)	$ 212,341	$ 239,974	$ (123,959)	$ 292,988
Earnings (loss) per common share before discontinued operations – diluted	**$ 1.47**	$ (.08)	$ 1.19	$ 1.29	$ (.67)	$ 1.59
Discontinued operations, net of tax	**–**	.07	(.07)	(.02)	–	–
	$ 1.47	$ (.01)	$ 1.12	$ 1.27	$ (.67)	$ 1.59
Common Stock Statistics						
Weighted average common shares outstanding – diluted (000's)	**189,693**	188,826	188,905	188,229	185,175	183,807
Dividends declared per common share	**$ .6950**	$ .6750	$ .6550	$ .6350	$ .6225	$ .6000
Book value per common share	**$ 15.01**	$ 13.95	$ 14.62	$ 14.22	$ 13.61	$ 14.95
Market price per common share (year end)	**$ 30.55**	$ 21.24	$ 21.46	$ 20.27	$ 23.60	$ 21.58
Market price ratios:						
Dividend payout	**47%**	(d)	58%	50%	(d)	38%
Yield	**2.3%**	3.2%	3.1%	3.2%	2.7%	2.9%
Market value as a percent of book value	**203.5%**	152.3%	146.8%	142.5%	173.4%	144.3%

(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.
Note: Intermountain, a natural gas distribution business, was acquired on October 1, 2008.

Item 6. Selected Financial Data (continued)

	2013	2012	2011	2010	2009	2008
General						
Total assets (000's)	**$7,061,332**	$6,682,491	$6,556,125	$6,303,549	$5,990,952	$6,587,845
Total long-term debt (000's)	**$1,854,563**	$1,744,975	$1,424,678	$1,506,752	$1,499,306	$1,647,302
Capitalization ratios:						
Common equity	**60%**	60%	66%	64%	63%	61%
Total debt	**40**	40	34	36	37	39
	100%	100%	100%	100%	100%	100%
Electric						
Retail sales (thousand kWh)	**3,173,086**	2,996,528	2,878,852	2,785,710	2,663,560	2,663,452
Electric system summer and firm purchase contract ZRCs (Interconnected system)	**583.5**	552.8	572.8	553.3	(a)	(a)
Electric system peak demand obligation, including firm purchase contracts, ZRCs (Interconnected system)	**508.3**	550.7	524.2	529.5	(a)	(a)
Demand peak – kW (Interconnected system)	**573,587**	573,587	535,761	525,643	525,643	525,643
Electricity produced (thousand kWh)	**2,430,001**	2,299,686	2,488,337	2,472,288	2,203,665	2,538,439
Electricity purchased (thousand kWh)	**971,261**	870,516	645,567	521,156	682,152	516,654
Average cost of fuel and purchased power per kWh	**$ .025**	$ .023	$ .021	$ .021	$ .023	$ .025
Natural Gas Distribution (b)						
Sales (Mdk)	**108,260**	93,810	103,237	95,480	102,670	87,924
Transportation (Mdk)	**149,490**	132,010	124,227	135,823	132,689	103,504
Degree days (% of normal)						
Montana-Dakota/Great Plains	**105%**	84%	101%	98%	104%	103%
Cascade	**98%**	96%	103%	96%	105%	108%
Intermountain	**110%**	91%	107%	100%	107%	90%
Pipeline and Energy Services						
Transportation (Mdk)	**178,598**	137,720	113,217	140,528	163,283	138,003
Gathering (Mdk)	**40,737**	47,084	66,500	77,154	92,598	102,064
Customer natural gas storage balance (Mdk)	**26,693**	43,731	36,021	58,784	61,506	30,598
Exploration and Production						
Production:						
Oil (MBbls)	**4,815**	3,694	2,724	2,767	2,557	2,232
NGL (MBbls)	**781**	828	776	495	554	576
Natural gas (MMcf)	**28,008**	33,214	45,598	50,391	56,632	65,457
Total production (MBOE)	**10,264**	10,058	11,099	11,661	12,550	13,717
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):						
Oil (per Bbl)	**$ 89.70**	$ 84.84	$ 91.62	$ 70.61	$ 53.57	$ 89.41
NGL (per Bbl)	**$ 37.39**	$ 39.81	$ 54.06	$ 44.93	$ 32.18	$ 54.65
Natural gas (per Mcf)	**$ 2.89**	$ 2.08	$ 3.30	$ 3.57	$ 2.99	$ 7.29
Average realized prices (including realized gain/loss on commodity derivatives):						
Oil (per Bbl)	**$ 89.35**	$ 86.54	$ 86.20	$ 69.59	$ 50.67	$ 88.66
NGL (per Bbl)	**$ 37.39**	$ 39.81	$ 54.06	$ 44.93	$ 32.18	$ 54.65
Natural gas (per Mcf)	**$ 2.96**	$ 2.91	$ 3.84	$ 4.36	$ 5.16	$ 7.38
Proved reserves:						
Oil (MBbls)	**41,019**	33,453	27,005	25,666	25,930	25,238
NGL (MBbls)	**6,602**	7,153	7,342	7,201	8,286	9,110
Natural gas (MMcf)	**198,445**	239,278	379,827	448,397	448,425	604,282
Total proved reserves (MBOE)	**80,695**	80,486	97,651	107,599	108,954	135,062
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	**24,713**	23,285	24,736	23,349	23,995	31,107
Asphalt (tons)	**6,228**	5,988	6,709	6,279	6,360	5,846
Ready-mixed concrete (cubic yards)	**3,223**	3,157	2,864	2,764	3,042	3,729
Aggregate reserves (000's tons)	**1,083,376**	1,088,236	1,088,833	1,107,396	1,125,491	1,145,161

(a) Information not available for periods prior to 2010.
(b) Intermountain was acquired on October 1, 2008.

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 safe and reliable 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, investments in 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/refining 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; develop and recruit talented employees; and continue growth through organic and acquisition opportunities. 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 Recruitment and retention of key personnel and 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 superior return on investment by: building new and strengthening existing customer relationships; effectively controlling costs; retaining, developing and recruiting talented employees; and 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,	**2013**	2012	2011
	(Dollars in millions, where applicable)		
Electric	**$ 34.8**	$ 30.6	$ 29.2
Natural gas distribution	**37.7**	29.4	38.4
Pipeline and energy services	**7.6**	26.6	23.1
Exploration and production	**94.5**	(177.2)	80.3
Construction materials and contracting	**50.9**	32.4	26.4
Construction services	**52.2**	38.4	21.6
Other	**5.1**	4.8	6.2
Intersegment eliminations	**(4.3)**	–	–
Earnings (loss) before discontinued operations	**278.5**	(15.0)	225.2
Income (loss) from discontinued operations, net of tax	**(.3)**	13.6	(12.9)
Earnings (loss) on common stock	**$278.2**	$ (1.4)	$212.3
Earnings (loss) per common share – basic:			
Earnings (loss) before discontinued operations	**$ 1.47**	$ (.08)	$ 1.19
Discontinued operations, net of tax	**–**	.07	(.07)
Earnings (loss) per common share – basic	**$ 1.47**	$ (.01)	$ 1.12
Earnings (loss) per common share – diluted:			
Earnings (loss) before discontinued operations	**$ 1.47**	$ (.08)	$ 1.19
Discontinued operations, net of tax	**–**	.07	(.07)
Earnings (loss) per common share – diluted	**$ 1.47**	$ (.01)	$ 1.12

2013 compared to 2012 Consolidated earnings for 2013 increased $279.6 million from the prior year. This increase was due to:

- Absence of the write-downs of oil and natural gas properties of $246.8 million (after tax), as discussed in Item 8 – Note 1, increased oil production and higher average realized natural gas and oil prices, partially offset by a lower realized gain on commodity derivatives of $21.1 million (after tax), higher depreciation, depletion and amortization expense, decreased natural gas production, higher production taxes, as well as higher general and administrative expense at the exploration and production business
- Higher asphalt and aggregate margins and volumes at the construction materials and contracting business

- Higher workloads and margins in the Western and Central regions, as well as higher equipment sales and rental revenue and margins at the construction services business
- Increased retail sales volumes and a gain on the sale of a nonregulated appliance service and repair business, partially offset by higher operation and maintenance expense, as well as higher depreciation, depletion and amortization expense at the natural gas distribution business

Partially offsetting these increases were:

- A net benefit in 2013 of $1.5 million (after tax) compared to $15.0 million (after tax) in 2012, related to the natural gas gathering operations litigation, as discussed in Item 8 – Note 19, as well as an impairment of coalbed natural gas gathering assets of $9.0 million (after tax) in 2013 compared to an impairment of $1.7 million (after tax) in 2012, as discussed in Item 8 – Note 1, at the pipeline and energy services business
- Loss from discontinued operations of $300,000 (after tax) in 2013, compared to income from discontinued operations of $13.6 million (after tax) in 2012, primarily due to the absence in 2013 of a net benefit in 2012 related to the reversal of an arbitration charge resulting from a favorable court ruling, as discussed in Item 8 – Note 3

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

Financial and Operating Data

Below are key financial and operating data for each of the Company's businesses.

Electric

Years ended December 31,	**2013**	2012	2011
	(Dollars in millions, where applicable)		
Operating revenues	**$257.3**	$236.9	$225.5
Operating expenses:			
Fuel and purchased power	**83.5**	72.4	64.5
Operation and maintenance	**76.5**	71.8	70.3
Depreciation, depletion and amortization	**32.8**	32.5	32.2
Taxes, other than income	**10.2**	10.3	9.4
	203.0	187.0	176.4
Operating income	**54.3**	49.9	49.1
Earnings	**$ 34.8**	$ 30.6	$ 29.2
Retail sales (million kWh)	**3,173.1**	2,996.5	2,878.9
Average cost of fuel and purchased power per kWh	**$ .025**	$ .023	$ .021

2013 compared to 2012 Electric earnings increased $4.2 million (14 percent) compared to the prior year due to:

- Higher electric retail sales margins, including the result of 6 percent higher volumes, primarily to residential, commercial and industrial customers due to increased residential customer growth and weather variances from last year
- Higher other income, largely higher allowance for funds used during construction of $800,000 (after tax)

These increases were partially offset by higher operation and maintenance expense, which includes $2.3 million (after tax) largely related to higher payroll-related costs and increased contract services, offset in part by lower benefit-related costs.

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, largely higher allowance for funds used during construction of $900,000 (after tax)
- Lower net interest expense, which includes $900,000 (after tax) due in part to higher capitalized interest

Partially offsetting these increases were:

- Higher income taxes, including $1.4 million which is partially related to the absence of an income tax benefit related to favorable resolutions 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, which includes $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

FORM 10-K

Natural Gas Distribution

Years ended December 31,	**2013**	2012	2011
	(Dollars in millions, where applicable)		
Operating revenues	**$851.9**	$754.8	$907.4
Operating expenses:			
Purchased natural gas sold	**534.8**	457.4	594.6
Operation and maintenance	**142.3**	139.4	137.3
Depreciation, depletion and amortization	**50.0**	45.7	44.6
Taxes, other than income	**46.0**	44.7	48.0
	773.1	687.2	824.5
Operating income	**78.8**	67.6	82.9
Earnings	**$ 37.7**	$ 29.4	$ 38.4
Volumes (MMdk):			
Sales	**108.3**	93.8	103.3
Transportation	**149.5**	132.0	124.2
Total throughput	**257.8**	225.8	227.5
Degree days (% of normal)*			
Montana-Dakota/Great Plains	**105%**	84%	101%
Cascade	**98%**	96%	103%
Intermountain	**110%**	91%	107%
Average cost of natural gas, including transportation, per dk	**$ 4.94**	$ 4.88	$ 5.76

* Degree days are a measure of the daily temperature-related demand for energy for heating.

2013 compared to 2012 The natural gas distribution business experienced an increase in earnings of $8.3 million (28 percent) compared to the prior year due to:

- Increased retail sales volumes of 15 percent, largely resulting from increased customer growth and colder weather than last year, partially offset by weather normalization adjustments in certain jurisdictions
- A $2.8 million (after tax) gain on the sale of Montana-Dakota's nonregulated appliance service and repair business
- Lower net interest expense, which includes $2.3 million (after tax) largely related to lower average interest rates

These increases were partially offset by:

- Higher operation and maintenance expense, which includes $3.4 million (after tax) largely related to higher payroll-related costs, offset in part by lower benefit-related costs
- Increased depreciation, depletion and amortization expense of $2.7 million (after tax), primarily resulting from higher property, plant and equipment balances
- Lower other income, which includes $2.0 million (after tax) largely related to lower allowance for funds used during construction

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
- Taxes other than income includes $1.3 million (after tax) primarily related to higher property taxes. Taxes other than income also reflects the effect of lower natural gas revenues.
- Absence in 2012 of a reduction of deferred income taxes, which includes $1.2 million primarily associated with benefits in 2011
- Increased operation and maintenance expense, which includes $700,000 (after tax) partially related to increased contract services

These decreases were partially offset by higher other income, which includes $1.1 million (after tax) primarily related to allowance for funds used during construction.

Pipeline and Energy Services

Years ended December 31,	**2013**	2012	2011
		(Dollars in millions)	
Operating revenues	**$202.1**	$193.1	$278.3
Operating expenses:			
Purchased natural gas sold	**57.5**	50.5	125.3
Operation and maintenance*	**81.8**	52.2	68.9
Depreciation, depletion and amortization	**29.1**	27.7	25.5
Taxes, other than income	**13.6**	13.6	13.2
	182.0	144.0	232.9
Operating income	**20.1**	49.1	45.4
Earnings*	**$ 7.6**	$ 26.6	$ 23.1
Transportation volumes (MMdk)	**178.6**	137.7	113.2
Natural gas gathering volumes (MMdk)	**40.7**	47.1	66.5
Customer natural gas storage balance (MMdk):			
Beginning of period	**43.7**	36.0	58.8
Net injection (withdrawal)	**(17.0)**	7.7	(22.8)
End of period	**26.7**	43.7	36.0

* Reflects an impairment of coalbed natural gas gathering assets of $14.5 million ($9.0 million after tax) in second quarter 2013 and $2.7 million ($1.7 million after tax) in second quarter 2012, as well as a net benefit of $2.5 million ($1.5 million after tax) in fourth quarter 2013 and $24.1 million ($15.0 million after tax) in second quarter 2012 related to the natural gas gathering operations litigation, largely reflected in operation and maintenance expense, as discussed in Item 8 – Note 19.

2013 compared to 2012 Pipeline and energy services earnings decreased $19.0 million (71 percent) largely due to:

- A net benefit in 2013 of $1.5 million (after tax) compared to $15.0 million (after tax) in 2012, related to the natural gas gathering operations litigation, as discussed in Item 8 – Note 19
- An impairment of coalbed natural gas gathering assets of $9.0 million (after tax) in 2013, compared to an impairment of $1.7 million (after tax) in 2012, largely resulting from lower natural gas prices, as discussed in Item 8 – Note 1
- Lower storage services revenue of $3.1 million (after tax), primarily due to lower average rates and lower storage balances
- Lower earnings of $3.1 million (after tax) resulting from lower natural gas gathering volumes from existing operations, largely resulting from customers experiencing production curtailments, normal declines and deferral of natural gas development activity

Partially offsetting the earnings decrease were:

- Higher earnings from the Company's interest in the Pronghorn oil and natural gas gathering and processing assets, which were acquired in May 2012, primarily due to higher volumes
- Lower operation and maintenance expense (excluding the asset impairments, net benefits related to the natural gas gathering operations litigation and Pronghorn-related expense), which includes $2.0 million (after tax), largely related to lower payroll-related costs, legal and contract services
- Lower depreciation, depletion and amortization expense (excluding depreciation on Pronghorn oil and natural gas gathering and processing assets), which includes $1.6 million (after tax), primarily related to the coalbed areas

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 the acquisition of the Company's interest in the Pronghorn oil and natural gas gathering and processing assets, 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.

Exploration and Production

Years ended December 31,	**2013**	2012	2011
	(Dollars in millions, where applicable)		
Operating revenues:			
Oil	**$431.9**	$ 313.4	$249.6
NGL	**29.2**	33.0	41.9
Natural gas	**81.0**	69.2	150.7
Realized gain on commodity derivatives	**.2**	33.6	9.6
Unrealized gain (loss) on commodity derivatives	**(6.3)**	(.6)	1.8
	536.0	448.6	453.6
Operating expenses:			
Operation and maintenance:			
Lease operating costs	**82.2**	77.7	75.6
Gathering and transportation	**15.4**	17.4	24.3
Other	**42.9**	37.0	36.5
Depreciation, depletion and amortization	**186.4**	160.7	142.6
Taxes, other than income:			
Production and property taxes	**46.6**	39.7	40.8
Other	**1.1**	1.0	–
Write-downs of oil and natural gas properties	**–**	391.8	–
	374.6	725.3	319.8
Operating income (loss)	**161.4**	(276.7)	133.8
Earnings (loss)	**$ 94.5**	$(177.2)	$ 80.3
Production:			
Oil (MBbls)	**4,815**	3,694	2,724
NGL (MBbls)	**781**	828	776
Natural gas (MMcf)	**28,008**	33,214	45,598
Total production (MBOE)	**10,264**	10,058	11,099
Average realized prices (excluding realized and unrealized gain/loss on commodity derivatives):			
Oil (per Bbl)	**$89.70**	$ 84.84	$91.62
NGL (per Bbl)	**$37.39**	$ 39.81	$54.06
Natural gas (per Mcf)	**$ 2.89**	$ 2.08	$ 3.30
Average realized prices (including realized gain/loss on commodity derivatives):			
Oil (per Bbl)	**$89.35**	$ 86.54	$86.20
NGL (per Bbl)	**$37.39**	$ 39.81	$54.06
Natural gas (per Mcf)	**$ 2.96**	$ 2.91	$ 3.84
Average depreciation, depletion and amortization rate, per BOE	**$17.41**	$ 15.28	$12.25
Production costs, including taxes, per BOE:			
Lease operating costs	**$ 8.01**	$ 7.73	$ 6.81
Gathering and transportation	**1.50**	1.73	2.19
Production and property taxes	**4.54**	3.94	3.67
	$14.05	$ 13.40	$12.67

2013 compared to 2012 Earnings at the exploration and production business increased $271.7 million due to:

- Absence of the write-downs of oil and natural gas properties of $246.8 million (after tax), as discussed in Item 8 – Note 1
- Increased oil production of 30 percent, primarily related to drilling activity in the Bakken and Paradox Basin areas
- Higher average realized natural gas prices of 39 percent, excluding gain/loss on commodity derivatives
- Higher average realized oil prices of 6 percent, excluding gain/loss on commodity derivatives

Partially offsetting these increases were:

- Lower realized gain on commodity derivatives of $21.1 million (after tax), due to higher commodity prices relative to hedge prices
- Higher depreciation, depletion and amortization expense of $16.2 million (after tax), largely due to higher depletion rates
- Decreased natural gas production of 16 percent, largely related to production curtailments, normal declines and deferral of certain natural gas development activity
- Higher production taxes of $4.3 million (after tax), primarily resulting from higher revenues
- Unrealized loss on commodity derivatives of $3.9 million (after tax) in 2013, compared to $400,000 (after tax) in 2012
- Higher general and administrative expense of $3.8 million (after tax), including higher payroll-related costs
- Higher net interest expense of $3.3 million (after tax), largely due to lower capitalized interest
- Increased lease operating expenses of $2.8 million (after tax), largely related to higher costs in the Bakken area resulting from increased production volumes and higher workover costs, as well as higher costs in the Paradox Basin resulting from increased production volumes, partially offset by lower costs at certain natural gas properties where curtailments of production have occurred

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

Construction Materials and Contracting

Years ended December 31,	**2013**	2012	2011
		(Dollars in millions)	
Operating revenues	**$1,712.1**	$1,617.4	$1,510.0
Operating expenses:			
Operation and maintenance	**1,505.2**	1,442.5	1,337.4
Depreciation, depletion and amortization	**74.5**	79.5	85.5
Taxes, other than income	**38.8**	37.5	36.0
	1,618.5	1,559.5	1,458.9
Operating income	**93.6**	57.9	51.1
Earnings	**$ 50.9**	$ 32.4	$ 26.4
Sales (000's):			
Aggregates (tons)	**24,713**	23,285	24,736
Asphalt (tons)	**6,228**	5,988	6,709
Ready-mixed concrete (cubic yards)	**3,223**	3,157	2,864

2013 compared to 2012 Earnings at the construction materials and contracting business increased $18.5 million (57 percent) due to:

- Higher earnings of $6.6 million (after tax) resulting from higher asphalt margins and volumes
- Higher earnings of $5.6 million (after tax) resulting from higher aggregate margins and volumes
- Lower selling, general and administrative costs of $2.4 million (after tax), largely lower insurance costs
- Higher earnings of $1.4 million (after tax) resulting from higher ready-mixed concrete margins and volumes
- Increased construction workloads and margins of $1.4 million (after tax)
- Higher earnings resulting from higher other product line volumes and margins

Partially offsetting these increases was higher interest expense of $1.3 million (after tax), resulting from higher average interest rates.

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

Construction Services

Years ended December 31,	**2013**	2012	2011
		(In millions)	
Operating revenues	**$1,039.8**	$938.6	$854.4
Operating expenses:			
Operation and maintenance	**910.7**	831.9	778.5
Depreciation, depletion and amortization	**11.9**	11.1	11.4
Taxes, other than income	**32.0**	29.1	25.4
	954.6	872.1	815.3
Operating income	**85.2**	66.5	39.1
Earnings	**$ 52.2**	$ 38.4	$ 21.6

2013 compared to 2012 Construction services earnings increased $13.8 million (36 percent) compared to the prior year primarily due to higher workloads and margins in the Western and Central regions, as well as higher equipment sales and rental revenue and margins. This increase was partially offset by higher general and administrative expense of $3.3 million (after tax), including higher payroll-related costs.

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.

Other

Years ended December 31,	2013	2012	2011
		(In millions)	
Operating revenues	**$9.6**	$10.4	$ 11.4
Operating expenses:			
Operation and maintenance	**.8**	3.3	4.7
Depreciation, depletion and amortization	**2.1**	2.0	1.6
Taxes, other than income	**.1**	.2	.1
	3.0	5.5	6.4
Operating income	**6.6**	4.9	5.0
Income from continuing operations	**5.1**	4.8	6.2
Income (loss) from discontinued operations, net of tax	**(.3)**	13.6	(12.9)
Earnings (loss)	**$4.8**	$18.4	$ (6.7)

2013 compared to 2012 Other earnings decreased $13.6 million compared to the prior year primarily due to a loss from discontinued operations of $300,000 (after tax) in 2013, compared to income from discontinued operations of $13.6 million (after tax) in 2012, primarily due to the absence in 2013 of a net benefit in 2012 related to the reversal of an arbitration charge for a guarantee of a construction contract at the domestic power production business, which was sold in 2007, as discussed in Item 8 – Note 3.

2012 compared to 2011 Other earnings increased $25.1 million compared to the prior year primarily due to income from discontinued operations of $13.6 million (after tax) in 2012, largely the net benefit related to the reversal of an arbitration charge, as previously discussed, compared to a loss from discontinued operations of $12.9 million (after tax) in 2011, largely related to the arbitration charge for a guarantee of a construction contract at the domestic power production business, which was sold in 2007, as discussed in Item 8 – Note 3.

Intersegment Transactions

Amounts presented in the preceding tables will not agree with the Consolidated Statements of Income due to the Company's elimination of intersegment transactions. The amounts relating to these items are as follows:

Years ended December 31,	2013	2012	2011
		(In millions)	
Intersegment transactions:			
Operating revenues	**$146.4**	$124.4	$190.1
Purchased natural gas sold	**87.2**	82.7	147.7
Operation and maintenance	**52.1**	41.7	42.4
Income taxes	**2.8**	–	–
Earnings on common stock	**4.3**	–	–

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.

- Adjusted earnings per common share for 2014 are projected in the range of $1.45 to $1.60. GAAP earnings guidance for 2014 is in the same range. Unrealized commodity derivatives fair values can fluctuate causing actual GAAP earnings to vary accordingly.
- The Company's long-term compound annual growth goals on earnings per common 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' Dakota Prairie Refinery has the construction materials and services business involved in constructing the facility, the exploration and production business supplying production, either directly or in kind, to the plant, the pipeline transporting natural gas to the plant and the utility supplying electricity.

Electric and natural gas distribution

- Rate base growth is projected to be approximately 9 percent compounded annually over the next five years, including plans for an approximate $1.3 billion capital investment program.
- Regulatory actions
  - The Company filed an application September 18, 2013, with the NDPSC for a natural gas rate increase, as discussed in Item 8 – Note 18.
  - The Company filed an application June 14, 2013, for an advance determination of prudence with the NDPSC to add pollution control equipment at the Lewis & Clark generating station projected to be completed in 2016 to comply with the Mercury and Air Toxics Standards rules. On October 9, 2013, the commission issued an order approving the advance determination of prudence.
  - The Company filed an application February 11, 2013, with the NDPSC for approval of an environmental cost recovery rider related to ongoing construction costs at the Big Stone Station for the installation of the BART air-quality control system, as discussed in Item 8 – Note 18.
  - The Company filed an application December 21, 2012, with the SDPUC for a natural gas rate increase requesting a total of $1.5 million annually or approximately 3.3 percent above current rates. The case includes the costs associated with the increased investment in facilities, including ongoing investment in new and replacement distribution facilities, an operations building, automated meter reading and new customer billing system. The Company implemented the full request July 22, 2013, subject to refund. On November 5, 2013, the commission approved a settlement stipulation for an increase of $900,000 annually, or 2.0 percent, effective with service rendered December 1, 2013.
  - The Company filed an application September 26, 2012, with the MTPSC for a natural gas rate increase, as discussed in Item 8 – Note 18.
  - Effective November 1, 2013, the WUTC approved recovery of $1.0 million over a one-year period for qualifying pipeline replacement projects. The WUTC issued a policy statement dated December 31, 2012, related to the accelerated replacement of natural gas pipeline facilities.
- The Company is constructing an 88-MW simple-cycle natural gas turbine and associated facilities, with an estimated project cost of $77 million and a projected in-service date in third quarter 2014. It is located on owned property 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.
- Investments are being made in 2014 totaling approximately $70 million to serve the growing electric and natural gas customer base associated with the Bakken oil development where customer growth is substantially higher than the national average.
- 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 engaged in a 30-mile, approximately $60 million natural gas line project into the Hanford Nuclear Site in Washington.
- The Company, along with a partner, expects to build a 345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota, about 160 miles, at a total cost of approximately $360 million. The Company's share would be one-half. The project is a MISO multi-value project. A route application was filed in August 2013, with the state of South Dakota, and in October 2013, with the state of North Dakota. The project is expected to be complete in 2019.
- 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.

Pipeline and energy services

- In January 2014, the Company launched an open season to obtain capacity commitments on a proposed 375-mile natural gas pipeline from western North Dakota to northwestern Minnesota to transport natural gas to markets in eastern North Dakota, Minnesota, Wisconsin, Michigan and other Midwest markets. The pipeline is expected to provide access to additional markets via interconnections with pipelines owned by Great Lakes Gas Transmission, Viking Gas Transmission and potentially TransCanada, in northwestern Minnesota. An interconnection with the Alliance Pipeline system in eastern North Dakota also is possible. Initially the pipeline would transport approximately 400 MMcf per day of natural gas and could be expanded to more than 500 MMcf per day. The project investment is estimated to be approximately $650 million. Following the open season, receipt of adequate capacity commitments and necessary permits and regulatory approvals, construction on the new pipeline could begin in 2016 with completion expected in 2017.

- The Company, in conjunction with Calumet, formed Dakota Prairie Refining, to develop, build and operate Dakota Prairie Refinery. Construction began on the facility in late March 2013 and, when complete, it will process Bakken crude into diesel, which will be marketed within the Bakken region. Other by-products, naphtha and atmospheric tower bottoms, will be railed to other areas. The total project cost estimate has been revised to approximately $350 million, with a projected in-service date in late 2014. EBITDA for the first year of operation is projected to be in the range of $70 million to $90 million, to be shared equally with Calumet.
- On October 31, 2013, WBI Energy Transmission filed a Section 4 rate case with the FERC, as discussed in Item 8 – Note 18.
- The Company is engaged in various natural gas pipeline projects to be constructed in 2014, including connections for the planned Garden Creek II natural gas processing plant in the Bakken, an expansion of its transmission system to increase capacity to the Black Hills and a 24-mile pipeline and related processing facilities to transport Fidelity's Paradox Basin natural gas production. The total cost for these projects is approximately $50 million.
- The Company continues to pursue expansion of facilities and services offered to customers. Energy development within its geographic region is expanding, most notably in the Bakken area, where the Company owns an extensive natural gas pipeline system. Ongoing energy development is expected to continue to provide growth opportunities for this business.

Exploration and production

- The Company expects to spend approximately $440 million in capital expenditures in 2014.
- For 2014, the Company expects a 10 to 20 percent increase in oil production and a 5 to 10 percent increase in NGL production. Natural gas production is expected to decline 20 to 30 percent compared to a year ago, primarily the result of the divestment of certain non-strategic natural gas-based properties in 2013. The vast 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 four drilling rigs deployed on its acreage in the Bakken and Paradox Basin areas, with two rigs operating in each area.
- Bakken areas
  - The Company owns a total of approximately 125,000 net acres of leaseholds in Mountrail and Stark counties, North Dakota and Richland County, Montana. The Middle Bakken and Three Forks formations are targeted in North Dakota and the Red River formation is targeted in Montana.
  - Capital expenditures are expected to total approximately $130 million in 2014.
  - Net oil production for the fourth quarter 2013 was approximately 7,900 BOPD which is down 5 percent from third quarter 2013. This quarter-on-quarter drop in oil production was primarily driven by weather-related downtime in December 2013, as well as delay of a three-well pad completion.
  - Alternative completion techniques, including increased stage count and cemented liners in the Middle Bakken (Mountrail County) and Three Forks (Mountrail and Stark counties) are being tested, with completion design changes to be finalized later in 2014.
- Paradox Basin, Utah
  - The Company owns approximately 130,000 net acres of leaseholds including its recent acquisition of 35,000 net acres of leaseholds and has an option to earn another 20,000 acres. The Company expects to further expand its acreage in the basin.
  - Capital expenditures are expected to total approximately $170 million in 2014.
  - Well costs have increased and now range from $10 million to $11 million per well driven by increased lateral lengths. With longer lateral lengths, estimated ultimate recoveries are expected to increase with the upper range now at 1.5 MMBbls of oil per well.
  - Following nine months of flowing at a constant 1,500 BOPD gross, the CCU 12-1 well came off its plateau rate and for the past seven months has still been flowing at approximately 1,000 BOPD. Cumulative production is 600 MBbls of oil.
  - Net oil production for fourth quarter 2013 was approximately 2,850 BOPD, up 89 percent from fourth quarter 2012 and 24 percent higher than third quarter 2013. Current production is approximately 3,000 BOPD.
  - The CCU 7-1 well has just been completed and is in the initial flowback and production ramp up period. Flowing on a 5/64 choke, the well was producing 350 BOPD at more than 3,000 psi flowing pressure. The well will be brought to full production capability over the next month. The CCU 36-1 has been flowing consistently at an average rate of 930 BOPD gross since October 11, 2013, with an average flowing pressure of approximately 3,400 psi.

- The Company's understanding of this play and the quality of the play continues to improve. It is anticipated that this field will play a key role in the Company's oil growth strategy.

- Other opportunities
  - The Company has continued its focus on adding a third oil play and on February 10, 2014, entered into an agreement to purchase working interests and leasehold positions in oil and natural gas production assets in the southern Powder River Basin of Wyoming. Current net production is more than 1,100 BOE per day, 80 percent of which is oil, with additional production expected to be on line before closing. For more information, see Item 8 – Note 20.

- Earnings guidance reflects estimated average NYMEX index prices for February through December 2014 in the range of $90 to $95 per Bbl of crude oil and $3.75 to $4.25 per Mcf of natural gas. Estimated prices for NGL are in the range of $35 to $45 per Bbl.

- Derivatives
  - The Company has derivative instruments for 11,000 BOPD for the first six months of 2014, 10,000 BOPD for July through September 2014 and 5,000 BOPD for October through December 2014, utilizing swaps with a weighted average price of $94.90. Covering full-year 2014, the Company has derivative instruments for 40,000 MMBtu of natural gas per day utilizing swaps at a weighted average price of $4.10.
  - For 2015, the Company has a derivative instrument for 10,000 MMBtu of natural gas per day utilizing a swap at $4.28.
  - The commodity derivative instruments that are in place as of February 18, 2014, are summarized in the following chart:

Commodity	Type	Index	Period Outstanding	Forward Notional Volume (Bbl/MMBtu)	Price (Per Bbl/MMBtu)
Crude Oil	Swap	NYMEX	1/14 – 6/14	181,000	$ 95.15
Crude Oil	Swap	NYMEX	1/14 – 6/14	181,000	$ 95.00
Crude Oil	Swap	NYMEX	1/14 – 6/14	181,000	$ 90.00
Crude Oil	Swap	NYMEX	1/14 – 6/14	181,000	$ 91.00
Crude Oil	Swap	NYMEX	1/14 – 6/14	181,000	$ 92.00
Crude Oil	Swap	NYMEX	1/14 – 6/14	181,000	$ 93.00
Crude Oil	Swap	NYMEX	1/14 – 6/14	181,000	$ 98.00
Crude Oil	Swap	NYMEX	1/14 – 6/14	181,000	$ 99.00
Crude Oil	Swap	NYMEX	1/14 – 6/14	181,000	$100.07
Crude Oil	Swap	NYMEX	1/14 – 12/14	365,000	$ 94.05
Crude Oil	Swap	NYMEX	1/14 – 12/14	365,000	$ 95.00
Crude Oil	Swap	NYMEX	7/14 – 9/14	184,000	$ 95.75
Crude Oil	Swap	NYMEX	7/14 – 9/14	184,000	$ 96.00
Crude Oil	Swap	NYMEX	7/14 – 9/14	92,000	$ 96.25
Crude Oil	Swap	NYMEX	7/14 – 12/14	184,000	$ 94.25
Crude Oil	Swap	NYMEX	7/14 – 12/14	184,000	$ 95.00
Crude Oil	Swap	NYMEX	7/14 – 12/14	184,000	$ 95.25
Natural Gas	Swap	NYMEX	1/14 – 12/14	7,300,000	$ 4.13
Natural Gas	Swap	NYMEX	1/14 – 12/14	3,650,000	$ 4.05
Natural Gas	Swap	NYMEX	1/14 – 12/14	3,650,000	$ 4.10
Natural Gas	Swap	NYMEX	1/15 – 12/15	3,650,000	$ 4.28

Construction materials and contracting

- Approximate work backlog as of December 31, 2013, was $456 million, compared to $406 million a year ago. Private work represents 11 percent of construction backlog and public work represents 89 percent of backlog. The backlog includes a variety of projects such as highway grading, paving and underground projects, airports, bridge work, reclamation and harbor expansions.
- The Company's approximate backlog in North Dakota as of December 31, 2013, was $97 million. North Dakota backlog was $46 million a year ago.
- Projected revenues included in the Company's 2014 earnings guidance are in the range of $1.6 billion to $1.8 billion.
- The Company anticipates margins in 2014 to be in line with 2013 margins.
- 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 sixth-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

- Approximate work backlog as of December 31, 2013, was $459 million, compared to $325 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.
- Projected revenues included in the Company's 2014 earnings guidance are in the range of $1.0 billion to $1.1 billion.
- The Company anticipates lower margins in 2014 compared to 2013.
- 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, NGL 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, plus the effects of cash flow hedges, less applicable income taxes. Proved reserves and associated future cash flows are determined based on SEC Defined Prices and exclude cash flows associated with asset retirement obligations that have been accrued on the balance sheet. 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 segment management regularly reviews 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, 2013, 2012, and 2011, there were no impairment losses recorded. At December 31, 2013, 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 5 percent to 10 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 2013. 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 2013.

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 $1.5 million (after tax) for the year ended December 31, 2013.

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 expense by less than $5.0 million for the year ended December 31, 2013.

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, 2013, the Company had cash and cash equivalents of $45.2 million and available capacity of $569.4 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 2013 increased $157.5 million from 2012. The increase was primarily due to lower working capital requirements of $132.9 million, primarily at the exploration and production and construction materials and contracting businesses and higher income from continuing operations, largely at the exploration and production business.

Cash flows provided by operating activities in 2012 decreased $41.9 million from 2011, 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.

Investing activities Cash flows used in investing activities in 2013 decreased $105.3 million from 2012 primarily due to higher proceeds from the sale of properties, largely at the exploration and production business, as well as lower acquisition-related capital expenditures, primarily at the pipeline and energy services business. Partially offsetting the decrease in cash flows used in investing activities was higher ongoing capital expenditures of $36.5 million, largely related to Dakota Prairie Refinery at the pipeline and energy services business and electric generation projects at the electric business, partially offset by lower capital expenditures at the exploration and production business.

Cash flows used in investing activities in 2012 increased $423.4 million from 2011 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.

Financing activities Cash flows provided by financing activities in 2013 decreased $152.8 million from 2012, primarily due to higher repayment of long-term debt of $284.9 million. Partially offsetting the decrease in cash flows provided by financing activities were lower dividends paid of $61.4 million resulting from the Company accelerating the payment date for the quarterly common stock dividend from January 1, 2013 to December 31, 2012; higher issuance of long-term debt of $40.0 million; as well as a cash contribution of $27.0 million related to the noncontrolling interest.

Cash flows provided by financing activities in 2012 increased $410.8 million from 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.

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, 2013, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $67.9 million. Pretax pension expense reflected in the years ended December 31, 2013, 2012 and 2011, was $3.0 million, $204,000 and $3.7 million, respectively. The Company's pension expense is currently projected to be approximately $2.5 million to $3.5 million in 2014. Funding for the pension plans is actuarially determined. The minimum required contributions for 2013, 2012 and 2011 were approximately $13.2 million, $16.1 million and $9.3 million, respectively. For more information on the Company's pension plans, see Item 8 – Note 16.

Capital expenditures

The Company's capital expenditures for 2011 through 2013 and as anticipated for 2014 through 2016 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated*		
	2011	2012	**2013**	2014	2015	2016
			(In millions)			
Capital expenditures:						
Electric	$ 52	$ 112	**$ 169**	$161	$ 140	$ 88
Natural gas distribution	71	130	**101**	141	166	139
Pipeline and energy services**	45	134	**127**	162	44	67
Exploration and production	273	554	**391**	441	501	518
Construction materials and contracting	52	45	**35**	38	69	58
Construction services	10	15	**15**	22	14	15
Other	19	1	**2**	1	3	3
Net proceeds from sale or disposition of property and other	(41)	(57)	**(112)**	(7)	(5)	(7)
Net capital expenditures	481	934	**728**	959	932	881
Retirement of long-term debt	85	139	**424**	12	269	294
	$566	$1,073	**$1,152**	$971	$1,201	$1,175

* 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 the Pronghorn oil and natural gas gathering and processing assets, as discussed in Item 8 – Note 2. 2013 – 2016 include the Company's share of capital expenditures related to Dakota Prairie Refinery and excludes expenditures related to the proposed 375-mile natural gas pipeline at the pipeline and energy services business, as discussed in Prospective Information and Item 8 – Note 19.

Capital expenditures for 2013, 2012 and 2011 in the preceding table include noncash capital expenditure-related accounts payable and exclude capital expenditures of the noncontrolling interest related to Dakota Prairie Refinery. These net transactions were $(56.8) million in 2013, $33.7 million in 2012 and $24.0 million in 2011.

The 2013 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 2014 through 2016 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
- The Company's proportionate share of Dakota Prairie Refinery at the pipeline and energy services segment
- Other growth opportunities

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 2014 through 2016 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, 2013. 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 revolving credit facilities of the Company and its subsidiaries at December 31, 2013:

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	$78.9 (b)	$ –	10/4/17
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (c)	$11.5	$2.2 (d)	7/9/18
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (e)	$ 3.0	$ –	7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/ Revolving credit agreement (f)	$500.0	$75.0 (b)	$ –	6/8/17

(a) The commercial paper program is supported by a revolving credit agreement with various banks (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) The outstanding letter of credit, as discussed in Item 8 – Note 19, reduces the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $90 million.
(f) The commercial paper program is supported by a revolving credit agreement with various banks (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.

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. 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 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 4.8 times for the 12 months ended December 31, 2013. 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.

Total equity as a percent of total capitalization was 60 percent at both December 31, 2013 and 2012. This ratio is calculated as the Company's total 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 total equity. This ratio indicates how a company is financing its operations, as well as its financial strength.

On May 20, 2013, the Company entered into an Equity Distribution Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 7.5 million shares of the Company's common stock. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement. Sales of such common stock may not be made after February 28, 2016. Proceeds from the shares of common stock under the agreement are expected to be used for corporate development purposes and other general corporate purposes. The Company issued 499,330 shares of stock during the fourth quarter of 2013 under the Equity Distribution Agreement, receiving net proceeds of $14.6 million.

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.

Cascade Natural Gas Corporation On July 9, 2013, Cascade entered into a revolving credit agreement which replaced the previous revolving credit agreement and extended the termination date to July 9, 2018.

Intermountain Gas Company On July 15, 2013, Intermountain entered into a revolving credit agreement which replaced the previous revolving credit agreement and extended the termination date to July 13, 2018.

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.

WBI Energy Transmission, Inc. On September 12, 2013, WBI Energy Transmission entered into a $175 million amended and restated uncommitted long-term private shelf agreement with an expiration date of September 12, 2016. WBI Energy Transmission had $100.0 million of notes outstanding at December 31, 2013, which reduced capacity under this uncommitted private shelf agreement.

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, 2013, the Company's commitments under these obligations were as follows:

	2014	2015	2016	2017	2018	Thereafter	Total
				(In millions)			
Long-term debt	$ 12.3	$269.4	$293.8	$204.9	$130.2	$ 944.0	$1,854.6
Estimated interest payments*	92.2	88.2	66.2	56.7	53.8	466.1	823.2
Operating leases	32.8	26.6	22.2	17.8	13.5	45.7	158.6
Purchase commitments	635.8	281.6	170.7	100.3	73.4	910.8	2,172.6
Commodity derivatives	7.5	–	–	–	–	–	7.5
	$780.6	$665.8	$552.9	$379.7	$270.9	$2,366.6	$5,016.5

* Estimated interest payments are calculated based on the applicable rates and payment dates.

At December 31, 2013, the Company had total liabilities of $98.5 million related to asset retirement obligations that are excluded from the table above. Of the total asset retirement obligations, the current portion was approximately $18.0 million at December 31, 2013, 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 2014, which are not reflected in the previous table, are $10.9 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.

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2013, 2012 or 2011.

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 on forecasted sales of oil and natural gas production.

The following table summarizes derivative agreements entered into by Fidelity as of December 31, 2013. 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 2014	$94.74	2,911	$(4,771)
Natural gas swap agreements maturing in 2014	$ 4.10	14,600	$(1,265)
Natural gas swap agreement maturing in 2015	$ 4.28	3,650	$ 503

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

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 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 called 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.

At December 31, 2013, the Company had no outstanding interest rate hedges.

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 shows the amount of debt, including current portion, and related weighted average interest rates, both by expected maturity dates, as of December 31, 2013.

	2014	2015	2016	2017	2018	Thereafter	Total	Fair Value
	(Dollars in millions)							
Long-term debt:								
Fixed rate	$9.3	$266.4	$288.5	$ 43.5	$108.4	$906.5	$1,622.6	$1,683.0
Weighted average interest rate	6.9%	5.7%	6.4%	6.3%	6.1%	5.1%	5.6%	–
Variable rate	$3.0	$ 3.0	$ 5.3	$161.4	$ 21.8	$ 37.5	$ 232.0	$ 229.6
Weighted average interest rate	1.2%	1.2%	1.8%	.5%	2.0%	2.4%	1.0%	–

Foreign currency risk

The Company's 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, 2013 and 2012, 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, 2013. 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 (1992)*.

Based on our evaluation under the framework in *Internal Control-Integrated Framework (1992)*, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2013.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2013, 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, 2013 and 2012, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2013. 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, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, 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, 2013, based on the criteria established in *Internal Control-Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 21, 2014

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, 2013, based on criteria established in *Internal Control-Integrated Framework (1992)* 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, 2013, based on the criteria established in *Internal Control-Integrated Framework (1992)* 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, 2013 of the Company and our report dated February 21, 2014 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 21, 2014

Consolidated Statements of Income

Years ended December 31,	2013	2012	2011
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and pipeline and energy services	**$ 1,264,574**	$1,131,626	$1,343,714
Exploration and production, construction materials and contracting, construction services and other	**3,197,830**	2,943,805	2,706,778
Total operating revenues	**4,462,404**	4,075,431	4,050,492
Operating expenses:			
Fuel and purchased power	**83,528**	72,380	64,485
Purchased natural gas sold	**505,065**	425,220	572,187
Operation and maintenance:			
Electric, natural gas distribution and pipeline and energy services	**269,825**	254,194	275,866
Exploration and production, construction materials and contracting, construction services and other	**2,535,872**	2,377,285	2,215,269
Depreciation, depletion and amortization	**386,856**	359,205	343,395
Taxes, other than income	**188,359**	176,140	172,923
Write-downs of oil and natural gas properties (Note 1)	**–**	391,800	–
Total operating expenses	**3,969,505**	4,056,224	3,644,125
Operating income	**492,899**	19,207	406,367
Earnings (loss) from equity method investments	**(132)**	5,383	4,693
Other income	**6,768**	6,642	6,520
Interest expense	**83,917**	76,699	81,354
Income (loss) before income taxes	**415,618**	(45,467)	336,226
Income taxes	**136,736**	(31,146)	110,274
Income (loss) from continuing operations	**278,882**	(14,321)	225,952
Income (loss) from discontinued operations, net of tax (Note 3)	**(312)**	13,567	(12,926)
Net income (loss)	**278,570**	(754)	213,026
Net loss attributable to noncontrolling interest	**(363)**	–	–
Dividends declared on preferred stocks	**685**	685	685
Earnings (loss) on common stock	**$ 278,248**	$ (1,439)	$ 212,341
Earnings (loss) per common share – basic:			
Earnings (loss) before discontinued operations	**$ 1.47**	$ (.08)	$ 1.19
Discontinued operations, net of tax	**–**	.07	(.07)
Earnings (loss) per common share – basic	**$ 1.47**	$ (.01)	$ 1.12
Earnings (loss) per common share – diluted:			
Earnings (loss) before discontinued operations	**$ 1.47**	$ (.08)	$ 1.19
Discontinued operations, net of tax	**–**	.07	(.07)
Earnings (loss) per common share – diluted	**$ 1.47**	$ (.01)	$ 1.12
Weighted average common shares outstanding – basic	**188,855**	188,826	188,763
Weighted average common shares outstanding – diluted	**189,693**	188,826	188,905

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Comprehensive Income

Years ended December 31,	**2013**	2012	2011
		(In thousands)	
Net income (loss)	**$278,570**	$ (754)	$213,026
Other comprehensive income (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 $(3,116), $4,829 and $4,683 in 2013, 2012 and 2011, respectively	**(5,594)**	8,497	7,900
Reclassification adjustment for (gain) loss on derivative instruments included in net income, net of tax of $(2,548), $(5,141) and $0 in 2013, 2012 and 2011, respectively	**(4,189)**	(8,754)	–
Net unrealized gain (loss) on derivative instruments qualifying as hedges	**(9,783)**	(257)	7,900
Postretirement liability adjustment:			
Postretirement liability gains (losses) arising during the period, net of tax of $11,818, $(2,060) and $(14,205) in 2013, 2012 and 2011, respectively	**18,539**	(3,106)	(23,473)
Amortization of postretirement liability losses included in net periodic benefit cost, net of tax of $1,276, $1,379 and $632 in 2013, 2012 and 2011, respectively	**2,001**	2,079	1,046
Postretirement liability adjustment	**20,540**	(1,027)	(22,427)
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of $(177), $(296) and $(767) in 2013, 2012 and 2011, respectively	**(299)**	(476)	(1,189)
Reclassification adjustment for (gain) loss on foreign currency translation adjustment included in net income, net of tax of $70, $2 and $(65) in 2013, 2012 and 2011, respectively	**143**	3	(106)
Foreign currency translation adjustment	**(156)**	(473)	(1,295)
Net unrealized gain (loss) on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(105), $(52) and $(20) in 2013, 2012 and 2011, respectively	**(194)**	(97)	(36)
Reclassification adjustment for loss on available-for-sale investments included in net income, net of tax of $59, $72 and $64 in 2013, 2012 and 2011, respectively	**109**	134	118
Net unrealized gain (loss) on available-for-sale investments	**(85)**	37	82
Other comprehensive income (loss)	**10,516**	(1,720)	(15,740)
Comprehensive income (loss)	**289,086**	(2,474)	197,286
Comprehensive loss attributable to noncontrolling interest	**(363)**	–	–
Comprehensive income (loss) attributable to common stockholders	**$289,449**	$(2,474)	$197,286

The accompanying notes are an integral part of these consolidated financial statements.

FORM 10-K

Consolidated Balance Sheets

December 31,	2013	2012
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	**$ 45,225**	$ 49,042
Receivables, net	**713,067**	678,123
Inventories	**282,391**	317,415
Deferred income taxes	**25,048**	22,846
Commodity derivative instruments	**1,447**	18,304
Prepayments and other current assets	**49,510**	42,351
Total current assets	**1,116,688**	1,128,081
Investments	**112,939**	103,243
Property, plant and equipment (Note 1)	**8,803,866**	8,107,751
Less accumulated depreciation, depletion and amortization	**3,872,487**	3,608,912
Net property, plant and equipment	**4,931,379**	4,498,839
Deferred charges and other assets:		
Goodwill (Note 5)	**636,039**	636,039
Other intangible assets, net (Note 5)	**13,099**	17,129
Other	**251,188**	299,160
Total deferred charges and other assets	**900,326**	952,328
Total assets	**$7,061,332**	$6,682,491
Liabilities and Equity		
Current liabilities:		
Short-term borrowings (Note 9)	**$ 11,500**	$ 28,200
Long-term debt due within one year	**12,277**	134,108
Accounts payable	**404,961**	388,015
Taxes payable	**74,175**	46,475
Dividends payable	**33,737**	171
Accrued compensation	**69,661**	48,448
Commodity derivative instruments	**7,483**	–
Other accrued liabilities	**171,106**	204,698
Total current liabilities	**784,900**	850,115
Long-term debt (Note 9)	**1,842,286**	1,610,867
Deferred credits and other liabilities:		
Deferred income taxes	**859,306**	755,102
Other liabilities	**718,938**	818,159
Total deferred credits and other liabilities	**1,578,244**	1,573,261
Commitments and contingencies (Notes 16, 18 and 19)		
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 – 189,868,780 shares in 2013 and 189,369,450 shares in 2012	**189,869**	189,369
Other paid-in capital	**1,056,996**	1,039,080
Retained earnings	**1,603,130**	1,457,146
Accumulated other comprehensive loss	**(38,205)**	(48,721)
Treasury stock at cost – 538,921 shares	**(3,626)**	(3,626)
Total common stockholders' equity	**2,808,164**	2,633,248
Total stockholders' equity	**2,823,164**	2,648,248
Noncontrolling interest	**32,738**	–
Total equity	**2,855,902**	2,648,248
Total liabilities and equity	**$7,061,332**	$6,682,491

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Equity

Years ended December 31, 2013, 2012 and 2011

	Preferred Stock		Common Stock		Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Treasury Stock		Noncontrolling Interest	Total
	Shares	Amount	Shares	Amount				Shares	Amount		
						(In thousands, except shares)					
Balance at December 31, 2010	150,000	$15,000	188,901,379	$188,901	$1,026,349	$1,497,439	$(31,261)	(538,921)	$(3,626)	$ –	$2,692,802
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	150,000	15,000	189,332,485	189,332	1,035,739	1,586,123	(47,001)	(538,921)	(3,626)	–	2,775,567
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	150,000	15,000	189,369,450	189,369	1,039,080	1,457,146	(48,721)	(538,921)	(3,626)	–	2,648,248
Net income (loss)	–	–	–	–	–	278,933	–	–	–	(363)	278,570
Other comprehensive income	–	–	–	–	–	–	10,516	–	–	–	10,516
Dividends declared on preferred stocks	–	–	–	–	–	(685)	–	–	–	–	(685)
Dividends declared on common stock	–	–	–	–	–	(132,264)	–	–	–	–	(132,264)
Stock-based compensation	–	–	–	–	5,281	–	–	–	–	–	5,281
Net tax deficit on stock-based compensation	–	–	–	–	(1,419)	–	–	–	–	–	(1,419)
Issuance of common stock	–	–	499,330	500	14,054	–	–	–	–	–	14,554
Contribution from noncontrolling interest	–	–	–	–	–	–	–	–	–	33,101	33,101
Balance at December 31, 2013	**150,000**	**$15,000**	**189,868,780**	**$189,869**	**$1,056,996**	**$1,603,130**	**$(38,205)**	**(538,921)**	**$(3,626)**	**$32,738**	**$2,855,902**

The accompanying notes are an integral part of these consolidated financial statements.

Consolidated Statements of Cash Flows

Years ended December 31,	2013	2012	2011
		(In thousands)	
Operating activities:			
Net income (loss)	**$ 278,570**	$ (754)	$ 213,026
Income (loss) from discontinued operations, net of tax	**(312)**	13,567	(12,926)
Income (loss) from continuing operations	**278,882**	(14,321)	225,952
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**386,856**	359,205	343,395
Earnings (loss), net of distributions, from equity method investments	**2,281**	(618)	(2,111)
Deferred income taxes	**86,778**	(7,503)	118,925
Unrealized (gain) loss on commodity derivatives	**6,267**	624	(1,827)
Write-downs of oil and natural gas properties (Note 1)	**–**	391,800	–
Changes in current assets and liabilities, net of acquisitions:			
Receivables	**(40,669)**	(13,416)	(30,452)
Inventories	**30,452**	(42,334)	(24,226)
Other current assets	**(9,474)**	297	7,729
Accounts payable	**15,084**	6,352	(12,263)
Other current liabilities	**29,392**	(59,001)	33,738
Other noncurrent changes	**(43,937)**	(33,665)	(31,538)
Net cash provided by continuing operations	**741,912**	587,420	627,322
Net cash provided by (used in) discontinued operations	**281**	(2,680)	(674)
Net cash provided by operating activities	**742,193**	584,740	626,648
Investing activities:			
Capital expenditures	**(909,400)**	(872,920)	(497,000)
Acquisitions, net of cash acquired	**–**	(67,261)	(157)
Net proceeds from sale or disposition of property and other	**124,541**	40,110	40,107
Investments	**302**	9,725	(10,302)
Proceeds from sale of equity method investments	**1,896**	2,394	2,807
Net cash used in continuing operations	**(782,661)**	(887,952)	(464,545)
Net cash provided by discontinued operations	**–**	–	–
Net cash used in investing activities	**(782,661)**	(887,952)	(464,545)
Financing activities:			
Issuance of short-term borrowings	**9,500**	20,100	–
Repayment of short-term borrowings	**–**	–	(20,000)
Issuance of long-term debt	**507,924**	467,957	300
Repayment of long-term debt	**(423,707)**	(138,775)	(85,151)
Proceeds from issuance of common stock	**14,554**	88	5,744
Dividends paid	**(98,405)**	(159,768)	(123,323)
Excess tax benefit on stock-based compensation	**–**	26	1,239
Contribution from noncontrolling interest	**27,000**	–	–
Net cash provided by (used in) continuing operations	**36,866**	189,628	(221,191)
Net cash provided by discontinued operations	**–**	–	–
Net cash provided by (used in) financing activities	**36,866**	189,628	(221,191)
Effect of exchange rate changes on cash and cash equivalents	**(215)**	(146)	(214)
Decrease in cash and cash equivalents	**(3,817)**	(113,730)	(59,302)
Cash and cash equivalents – beginning of year	**49,042**	162,772	222,074
Cash and cash equivalents – end of year	**$ 45,225**	$ 49,042	$ 162,772

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. Intercompany balances and transactions have been eliminated in consolidation, except for certain transactions related to the Company's regulated operations in accordance with GAAP. 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, 2013, 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. For more information, see Percentage-of-completion method in this note. The total balance of receivables past due 90 days or more was $36.4 million and $34.3 million as of December 31, 2013 and 2012, 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, 2013 and 2012, was $10.1 million and $10.8 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:

	2013	2012
	(In thousands)	
Aggregates held for resale	**$101,568**	$ 87,715
Materials and supplies	**69,808**	69,390
Asphalt oil	**38,099**	67,480
Merchandise for resale	**21,720**	31,172
Natural gas in storage (current)	**16,417**	29,030
Other	**34,779**	32,628
Total	**$282,391**	$317,415

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 $48.3 million and $49.7 million at December 31, 2013 and 2012, respectively.

Investments

The Company's investments include its equity method and cost method investments as discussed in Note 4, the cash surrender value of life insurance policies, an insurance 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 measures its investment in the insurance 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:

	2013	2012	2011
		(In thousands)	
Interest capitalized	**$6,033**	$8,659	$10,821
AFUDC – borrowed	**$2,767**	$2,483	$ 1,666
AFUDC – equity	**$3,322**	$4,530	$ 2,587

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.

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

	2013	2012	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	**$ 570,394**	$ 546,011	42
Distribution	**308,202**	276,446	39
Transmission	**196,824**	180,543	48
Construction in progress	**141,365**	62,123	–
Other	**99,037**	85,461	14
Natural gas distribution:			
Distribution	**1,384,587**	1,308,314	40
Construction in progress	**46,763**	71,679	–
Other	**345,551**	309,957	25
Pipeline and energy services:			
Transmission	**418,594**	403,126	52
Gathering	**39,597**	42,420	19
Storage	**42,939**	42,058	51
Construction in progress	**6,937**	13,667	–
Other	**39,504**	38,386	29
Nonregulated:			
Pipeline and energy services:			
Midstream	**213,063**	233,840	17
Construction in progress	**188,641**	29,657	–
Other	**12,897**	13,379	11
Exploration and production:			
Oil and natural gas properties	**3,017,879**	2,723,356	*
Other	**42,969**	41,204	8
Construction materials and contracting:			
Land	**125,551**	126,788	–
Buildings and improvements	**70,000**	73,884	19
Machinery, vehicles and equipment	**906,774**	899,592	12
Construction in progress	**13,315**	11,165	–
Aggregate reserves	**394,715**	393,552	**
Construction services:			
Land	**4,821**	4,723	–
Buildings and improvements	**16,628**	16,563	20
Machinery, vehicles and equipment	**105,991**	100,445	6
Other	**7,508**	8,893	4
Other:			
Land	**2,837**	2,837	–
Other	**47,160**	47,682	23
Eliminations	**(7,177)**	–	
Less accumulated depreciation, depletion and amortization	**3,872,487**	3,608,912	
Net property, plant and equipment	**$4,931,379**	$4,498,839	

* Amortized on the units-of-production method based on total proved reserves at a BOE average rate of $17.41, $15.28 and $12.25 for the years ended December 31, 2013, 2012 and 2011, respectively. Includes oil and natural gas properties accounted for under the full-cost method, of which $124.9 million and $191.8 million were excluded from amortization at December 31, 2013 and 2012, 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 2013 and 2012, the Company recognized impairments of $9.0 million (after tax) and $1.7 million (after tax), respectively, which are recorded in operation and maintenance expense on the Consolidated Statements of Income. The impairments are related to coalbed natural gas gathering assets located in Wyoming and Montana where there has been a significant decline in natural gas development and production activity largely due to low natural gas prices. The coalbed natural gas gathering assets were written down to fair value that was determined using the income approach. For more information on this nonrecurring fair value measurement, see Note 8.

No significant impairment losses were recorded in 2011. 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 segment management regularly reviews 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, 2013, 2012 and 2011, there were no impairment losses recorded. At December 31, 2013, 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 5 percent to 10 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 2013. 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, plus the effects of cash flow hedges, less applicable income taxes. Proved reserves and associated future cash flows are determined based on SEC Defined Prices and exclude cash outflows associated with asset retirement obligations that have been accrued on the balance sheet. 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.

At December 31, 2013, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, 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 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 hedged 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 at September 30, 2012 and December 31, 2012. 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.

The following table summarizes the Company's oil and natural gas properties not subject to amortization at December 31, 2013, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2013	2012	2011	2010 and prior
			(In thousands)		
Acquisition	$ 93,758	$ 1,514	$23,588	$28,543	$40,113
Development	14,824	12,622	1,633	271	298
Exploration	14,547	9,952	4,346	198	51
Capitalized interest	1,740	340	418	410	572
Total costs not subject to amortization	$124,869	$24,428	$29,985	$29,422	$41,034

Costs not subject to amortization as of December 31, 2013, consisted primarily of unevaluated leaseholds and development costs in the Bakken area, Texas properties and the Paradox Basin. 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 $107.4 million and $85.9 million at December 31, 2013 and 2012, 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 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 represent billings in excess of revenues recognized and were included in accounts payable. Costs and estimated earnings in excess of billings and billings in excess of costs and estimated earnings on uncompleted contracts at December 31, were as follows:

	2013	2012
	(In thousands)	
Costs and estimated earnings in excess of billings on uncompleted contracts	**$60,828**	$64,996
Billings in excess of costs and estimated earnings on uncompleted contracts	**$84,189**	$83,167

Amounts representing balances billed but not paid by customers under retainage provisions in contracts at December 31, were as follows:

	2013	2012
	(In thousands)	
Short-term retainage*	**$55,906**	$54,256
Long-term retainage**	**4,229**	2,038
Total retainage	**$60,135**	$56,294

* Expected to be paid within one year or less and included in receivables, net.
** Included in deferred charges and other assets – other.

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 42 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 $16.9 million and $35.3 million at December 31, 2013 and 2012, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $12.1 million and $3.0 million at December 31, 2013 and 2012, 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 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.

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. In 2013 and 2011, there were no shares excluded from the calculation of diluted earnings per share. 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:

	2013	2012	2011
		(In thousands)	
Weighted average common shares outstanding – basic	**188,855**	188,826	188,763
Effect of dilutive stock options and performance share awards	**838**	–	142
Weighted average common shares outstanding – diluted	**189,693**	188,826	188,905
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:

	2013	2012	2011
		(In thousands)	
Interest, net of amount capitalized	**$81,689**	$74,378	$ 78,133
Income taxes paid (refunded), net	**$24,857**	$ 3,277	$(12,287)

Noncash investing transactions at December 31 were as follows:

	2013	2012	2011
		(In thousands)	
Property, plant and equipment additions in accounts payable	**$67,129**	$76,205	$41,540

New accounting standards

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income In February 2013, the FASB issued guidance on the reporting of amounts reclassified out of accumulated other comprehensive income. This guidance requires an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required to be reclassified in its entirety to net income. Entities may present this information either on the face of the statement where net income is presented or in the notes. This guidance was effective for the Company on January 1, 2013, and is to be applied prospectively. The guidance required additional disclosures, however 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. In January 2013, the FASB issued guidance clarifying the scope of the disclosures related to balance sheet offsetting. The amendments clarify that this guidance only applies to derivative instruments, repurchase agreements and securities lending transactions that are either offset or subject to an enforceable master netting arrangement. The guidance was effective for the Company on January 1, 2013, and must be applied retrospectively. The guidance required additional disclosures, however it did 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 to determine if they are VIEs and if so, if the Company is the primary beneficiary. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, noncontrolling interest and results of activities of a VIE in its consolidated financial statements.

A VIE should be consolidated if a party with an ownership, contractual or other financial interest in the VIE (a variable interest holder) has the power to direct the VIE's most significant activities and the obligation to absorb losses or right to receive benefits of the VIE that could be significant to the VIE. A variable interest holder that consolidates the VIE is called the primary beneficiary. Upon consolidation, the primary beneficiary generally must initially record all of the VIE's assets, liabilities and noncontrolling interests at fair value and subsequently account for the VIE as if it were consolidated.

The Company's evaluation of whether it qualifies as the primary beneficiary of a VIE involves significant judgments, estimates and assumptions and includes a qualitative analysis of the activities that most significantly impact the VIE's economic performance and whether the Company has the power to direct those activities, the design of the entity, the rights of the parties and the purpose of the arrangement.

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 (losses) on available-for-sale investments. For more information on derivative instruments, see Note 7.

The after-tax changes in the components of accumulated other comprehensive loss as of December 31, 2013, 2012 and 2011, 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, 2011	$ 6,275	$(53,320)	$ (38)	$ 82	$(47,001)
Current-period other comprehensive income (loss)	(257)	(1,027)	(473)	37	(1,720)
Balance at December 31, 2012	6,018	(54,347)	(511)	119	(48,721)
Other comprehensive income (loss) before reclassifications	(5,594)	18,539	(299)	(194)	12,452
Amounts reclassified from accumulated other comprehensive loss	(4,189)	2,001	143	109	(1,936)
Net current-period other comprehensive income (loss)	(9,783)	20,540	(156)	(85)	10,516
Balance at December 31, 2013	**$(3,765)**	**$(33,807)**	**$(667)**	**$ 34**	**$(38,205)**

Reclassifications out of accumulated other comprehensive loss for the year ended December 31 were as follows:

	2013	Location on Consolidated Statements of Income
	(In thousands)	
Reclassification adjustment for gain (loss) on derivative instruments included in net income:		
Commodity derivative instruments	**$ 7,803**	Operating revenues
Interest rate derivative instruments	**(1,066)**	Interest expense
	6,737	
	(2,548)	Income taxes
	4,189	
Amortization of postretirement liability losses included in net periodic benefit cost	**(3,277)**	(a)
	1,276	Income taxes
	(2,001)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net income	**(213)**	Earnings (loss) from equity method investments
	70	Earnings (loss) from equity method investments
	(143)	
Reclassification adjustment for loss on available-for-sale investments included in net income	**(168)**	Other income
	59	Income taxes
	(109)	
Total reclassifications	**$ 1,936**	

(a) Included in net periodic benefit cost (credit). For more information, see Note 16.

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.

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 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. At December 31, 2013, the Company had no significant equity method investments.

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 of its entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE. The Company's remaining interest in ECTE is being sold over a four-year period. In August 2013 and 2012, and November 2011, the Company completed the sale of one-fourth of the remaining interest in each year. The Company recognized immaterial gains in 2013 and 2012 and a $1.0 million ($600,000 after tax) gain in 2011. The Company's remaining ownership interest in ECTE is being accounted for under the cost method.

At December 31, 2012, the equity method investments had total assets of $129.0 million and long-term debt of $65.5 million. The Company's investment in its equity method investments was approximately $6.9 million, including undistributed earnings of $3.4 million, at December 31, 2012.

Note 5 – Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2013, were as follows:

	Balance at January 1, 2013*	Goodwill Acquired During the Year	Balance at December 31, 2013*
		(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	104,276	–	104,276
Total	$636,039	$ –	$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.

The changes in the carrying amount of goodwill for the year ended December 31, 2012, were as follows:

	Balance at January 1, 2012*	Goodwill Acquired During the Year**	Balance at 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.

Other amortizable intangible assets at December 31 were as follows:

	2013	2012
	(In thousands)	
Customer relationships	**$ 21,310**	$ 21,310
Accumulated amortization	**(13,726)**	(11,701)
	7,584	9,609
Noncompete agreements	**6,186**	7,236
Accumulated amortization	**(4,840)**	(5,326)
	1,346	1,910
Other	**10,995**	10,979
Accumulated amortization	**(6,826)**	(5,369)
	4,169	5,610
Total	**$ 13,099**	$ 17,129

Amortization expense for amortizable intangible assets for the years ended December 31, 2013, 2012 and 2011, was $4.0 million, $3.8 million and $3.7 million, respectively. Estimated amortization expense for intangible assets is $3.2 million in 2014, $2.5 million in 2015, $2.2 million in 2016, $2.0 million in 2017, $1.0 million in 2018 and $2.2 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*	2013	2012
		(In thousands)	
Regulatory assets:			
Deferred income taxes	**	**$ 125,607**	$121,781
Pension and postretirement benefits (a)	(e)	**105,123**	166,477
Taxes recoverable from customers (a)	Over plant lives	**18,266**	9,078
Manufactured gas plant sites remediation (a)	Up to 4 years	**15,797**	15,828
Natural gas costs recoverable through rate adjustments (b)	Up to 28 months	**12,060**	2,981
Long-term debt refinancing costs (a)	Up to 25 years	**8,697**	9,144
Costs related to identifying generation development (a)	Up to 13 years	**4,512**	5,773
Other (a) (b)	Largely within 1 – 5 years	**15,311**	20,132
Total regulatory assets		**305,373**	351,194
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		**308,431**	296,037
Deferred income taxes**		**64,914**	82,077
Taxes refundable to customers (c)		**20,180**	24,212
Natural gas costs refundable through rate adjustments (d)		**16,932**	35,328
Other (c) (d)		**21,868**	12,828
Total regulatory liabilities		**432,325**	450,482
Net regulatory position		**$(126,952)**	$ (99,288)

* 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 – other 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, 2013 and 2012, approximately $163.7 million and $215.6 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, 2013, the Company had no outstanding foreign currency hedges.

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.

The Company evaluates counterparty credit risk on its derivative assets and the Company's credit risk on its derivative liabilities. As of December 31, 2013 and 2012, credit risk was not material.

Fidelity

At December 31, 2013 and 2012, Fidelity held oil swap and collar agreements with total forward notional volumes of 2.9 million and 2.6 million Bbl, respectively, and natural gas swap agreements with total forward notional volumes of 18.3 million and 11.0 million MMBtu, respectively. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of oil and natural gas on its forecasted sales of oil and natural gas production.

Effective April 1, 2013, Fidelity elected to de-designate all commodity derivative contracts previously designated as cash flow hedges and elected to discontinue hedge accounting prospectively for all of its commodity derivative instruments. When the criteria for hedge accounting is not met or when hedge accounting is not elected, realized gains and losses and unrealized gains and losses are both recorded in operating revenues on the Consolidated Statements of Income. As a result of discontinuing hedge accounting on commodity derivative instruments, gains and losses on the oil and natural gas derivative instruments remain in accumulated other comprehensive income (loss) as of the de-designation date and are reclassified into earnings in future periods as the underlying hedged transactions affect earnings. At April 1, 2013, accumulated other comprehensive income (loss) included $1.8 million of unrealized gains, representing the mark-to-market value of the Company's commodity derivative instruments that qualified as cash flow hedges as of the balance sheet date. The Company expects to reclassify into earnings from accumulated other comprehensive income (loss) the remaining value related to de-designating commodity derivative instruments over the next 12 months.

Prior to April 1, 2013, changes in the fair value attributable to the effective portion of the hedging instruments, net of tax, were recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). To the extent that the hedges were not effective or did not qualify for hedge accounting, the ineffective portion of the changes in fair market value was recorded directly in earnings. Gains and losses on the oil and natural gas derivative instruments were 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 were settled.

Centennial

At December 31, 2013, Centennial had no outstanding interest rate swap agreements. 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.

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. 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.

Fidelity and Centennial

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.

The gains and losses on derivative instruments for the years ended December 31 were as follows:

	2013	2012	2011
		(In thousands)	
Commodity derivatives designated as cash flow hedges:			
Amount of gain (loss) recognized in accumulated other comprehensive loss (effective portion), net of tax	**$(6,153)**	$10,209	$10,806
Amount of gain reclassified from accumulated other comprehensive loss into operating revenues (effective portion), net of tax	**(4,916)**	(8,788)	–
Amount of gain (loss) recognized in operating revenues (ineffective portion), before tax	**(1,422)**	(730)	1,827
Interest rate derivatives designated as cash flow hedges:			
Amount of gain (loss) recognized in accumulated other comprehensive loss (effective portion), net of tax	**559**	(1,712)	(2,906)
Amount of loss reclassified from accumulated other comprehensive loss into interest expense (effective portion), net of tax	**727**	34	–
Amount of loss recognized in interest expense (ineffective portion), before tax	**(769)**	–	–
Commodity derivatives not designated as hedging instruments:			
Amount of gain (loss) recognized in operating revenues, before tax	**(4,845)**	106	–

Based on December 31, 2013, fair values, over the next 12 months net losses of approximately $700,000 (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, 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 were in a liability position at December 31, 2013 and 2012, were $7.5 million and $6.3 million, respectively. 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, 2013 and 2012, were $7.5 million and $6.3 million, respectively.

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, 2013**	Fair Value at December 31, 2012
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	**$ –**	$18,084
		–	18,084
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	**1,447**	220
	Other assets – noncurrent	**503**	–
		1,950	220
Total asset derivatives		**$1,950**	$18,304

Liability Derivatives	Location on Consolidated Balance Sheets	**Fair Value at December 31, 2013**	Fair Value at December 31, 2012
		(In thousands)	
Designated as hedges:			
Interest rate derivatives	Other accrued liabilities	**$ –**	$ 6,255
		–	6,255
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	**7,483**	–
		7,483	–
Total liability derivatives		**$7,483**	$ 6,255

All of the Company's commodity and interest rate derivative instruments at December 31, 2013 and 2012, were subject to legally enforceable master netting agreements. However, 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. The gross derivative assets and liabilities (excluding settlement receivables and payables that may be subject to the same master netting agreements) presented on the Consolidated Balance Sheets and the amount eligible for offset under the master netting agreements is presented in the following table:

December 31, 2013	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
		(In thousands)	
Assets:			
Commodity derivatives	$ 1,950	$(1,950)	$ –
Total assets	$ 1,950	$(1,950)	$ –
Liabilities:			
Commodity derivatives	$ 7,483	$(1,950)	$ 5,533
Total liabilities	$ 7,483	$(1,950)	$ 5,533

December 31, 2012	Gross Amounts Recognized on the Consolidated Balance Sheets	Gross Amounts Not Offset on the Consolidated Balance Sheets	Net
		(In thousands)	
Assets:			
Commodity derivatives	$18,304	$ –	$18,304
Total assets	$18,304	$ –	$18,304
Liabilities:			
Interest rate derivatives	$ 6,255	$ –	$ 6,255
Total liabilities	$ 6,255	$ –	$ 6,255

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 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 $62.4 million and $48.9 million as of December 31, 2013 and 2012, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the year ended December 31, 2013 and 2012, were $13.5 million and $5.2 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 available-for-sale securities, which include 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. Unrealized gains or losses are recorded in accumulated other comprehensive income (loss). Details of available-for-sale securities were as follows:

December 31, 2013	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 8,151	$ 69	$(27)	$ 8,193
U.S. Treasury securities	1,906	15	(4)	1,917
Total	$10,057	$ 84	$(31)	$10,110

December 31, 2012	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 8,054	$144	$ (3)	$ 8,195
U.S. Treasury securities	1,763	43	–	1,806
Total	$ 9,817	$187	$ (3)	$10,001

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 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, 2013 and 2012, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2013, 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, 2013
	(In thousands)			
Assets:				
Money market funds	$ –	$19,227	$ –	$19,227
Insurance contract*	–	62,370	–	62,370
Available-for-sale securities:				
Mortgage-backed securities	–	8,193	–	8,193
U.S. Treasury securities	–	1,917	–	1,917
Commodity derivative instruments	–	1,950	–	1,950
Total assets measured at fair value	$ –	$93,657	$ –	$93,657
Liabilities:				
Commodity derivative instruments	$ –	$ 7,483	$ –	$ 7,483
Total liabilities measured at fair value	$ –	$ 7,483	$ –	$ 7,483

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

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	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
Insurance contract*	–	48,898	–	48,898
Available-for-sale securities:				
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 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 investments.

The Company applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements, including long-lived asset impairments. These assets are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The Company reviews the carrying value of its long-lived assets, excluding goodwill and oil and natural gas properties, whenever events or changes in circumstances indicate that such carrying amounts may not be recoverable. During the second quarters of 2013 and 2012, coalbed natural gas gathering assets were reviewed for impairment and found to be impaired and were written down to their estimated fair value using the income approach. Under this approach, fair value is determined by using the present value of future estimated cash flows. The factors used to determine the estimated future cash flows include, but are not limited to, internal estimates of gathering revenue, future commodity prices and operating costs and equipment salvage values. The estimated cash flows are discounted using a rate that approximates the weighted average cost of capital of a market participant. These fair value inputs are not typically observable. At June 30, 2012, certain coalbed natural gas gathering assets were written down to the nonrecurring fair value measurement of $2.5 million. At June 30, 2013, additional coalbed natural gas gathering assets were written down to the nonrecurring fair value measurement of $9.7 million. The fair value of these coalbed natural gas gathering assets have been categorized as Level 3 (Significant Unobservable Inputs) in the fair value hierarchy.

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:

	2013		2012	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$1,854,563**	**$1,912,590**	$1,744,975	$1,888,135

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. 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 revolving credit facilities of the Company and its subsidiaries:

Company	Facility	Facility Limit	Amount Outstanding at December 31, 2013	Amount Outstanding at December 31, 2012	Letters of Credit at December 31, 2013	Expiration Date
				(In millions)		
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$125.0	$78.9 (b)	$ 76.0 (b)	$ –	10/4/17
Cascade Natural Gas Corporation	Revolving credit agreement	$ 50.0 (c)	$11.5	$ 2.0	$ 2.2 (d)	7/9/18
Intermountain Gas Company	Revolving credit agreement	$ 65.0 (e)	$ 3.0	$ 26.2	$ –	7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (f)	$500.0	$75.0 (b)	$217.0 (b)	$ –	6/8/17

(a) The commercial paper program is supported by a revolving credit agreement with various banks (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) The outstanding letter of credit, as discussed in Note 19, reduces the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $90 million.
(f) The commercial paper program is supported by a revolving credit agreement with various banks (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.

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 On July 9, 2013, Cascade entered into a revolving credit agreement which replaced the previous revolving credit agreement and extended the termination date to July 9, 2018. Any borrowings under the revolving credit agreement would be classified as short-term borrowings as Cascade intends to repay the borrowings within one year. The weighted average interest rate for borrowings outstanding at December 31, 2013, was 3.3 percent.

The 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. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

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 revolving credit agreement.

Long-term debt

MDU Resources Group, Inc. 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).

On December 12, 2013, MDU Energy Capital entered into a note purchase agreement. MDU Energy Capital contracted to issue $30.0 million of Senior Notes under the agreement on January 27, 2014, with due dates ranging from January 2029 to January 2044 at a weighted average interest rate of 5.3 percent.

Intermountain Gas Company On July 15, 2013, Intermountain entered into a revolving credit agreement which replaced the previous revolving credit agreement and extended the termination date to July 13, 2018. These borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings. The borrowings outstanding as of December 31, 2012, were classified as short-term borrowings because the previous revolving credit agreement expired within one year.

The credit agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Intermountain's credit agreement also contains cross-default provisions. These provisions state that if Intermountain 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, or certain conditions result in an early termination date under any swap contract that is in excess of a specified amount, then Intermountain will be in default under the revolving credit agreement.

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 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.

WBI Energy Transmission, Inc. On September 12, 2013, WBI Energy Transmission entered into a $175 million amended and restated uncommitted long-term private shelf agreement with an expiration date of September 12, 2016. WBI Energy Transmission had $100.0 million of notes outstanding at December 31, 2013, which reduced capacity under this uncommitted private shelf agreement.

This 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 a limitation on priority debt and 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:

	2013	2012
	(In thousands)	
Senior Notes at a weighted average rate of 5.52%, due on dates ranging from June 19, 2015 to April 15, 2044	**$1,545,078**	$1,349,160
Commercial paper at a weighted average rate of .40%, supported by revolving credit agreements	**153,924**	293,000
Term Loan Agreements at a weighted average rate of 2.08%, due on dates ranging from April 22, 2014 to April 22, 2023	**75,000**	–
Medium-Term Notes at a weighted average rate of 7.32%, due on dates ranging from September 15, 2027 to March 16, 2029	**35,000**	59,000
Other notes at a weighted average rate of 5.23%, due on dates ranging from September 1, 2020 to February 1, 2035	**39,863**	40,090
Credit agreements at a weighted average rate of 4.11%, due on dates ranging from February 28, 2014 to November 30, 2038	**5,701**	3,768
Discount	**(3)**	(43)
Total long-term debt	**1,854,563**	1,744,975
Less current maturities	**12,277**	134,108
Net long-term debt	**$1,842,286**	$1,610,867

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2013, aggregate $12.3 million in 2014; $269.4 million in 2015; $293.8 million in 2016; $204.9 million in 2017; $130.2 million in 2018 and $944.0 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:

	2013	2012
	(In thousands)	
Balance at beginning of year	**$102,545**	$ 98,151
Liabilities incurred	**5,610**	6,523
Liabilities acquired	**–**	–
Liabilities settled	**(22,257)**	(10,472)
Accretion expense	**4,574**	4,266
Revisions in estimates	**7,671**	3,655
Other	**386**	422
Balance at end of year	**$ 98,529**	$102,545

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, 2013 and 2012, was $4.1 million and $5.0 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:

	2013	2012
	(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 2013, 2012 and 2011, 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

For the years 2013, 2012 and 2011, dividends declared on common stock were $.6950, $.6750 and $.6550 per common share, respectively.

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 2011 through December 2013, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2013, there were 15.6 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 following discusses the most restrictive limitations.

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 $2.1 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2013. 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 $219 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, 2013. 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, 2013, 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 (after tax) was $3.9 million, $4.0 million and $3.5 million in 2013, 2012 and 2011, respectively.

As of December 31, 2013, total remaining unrecognized compensation expense related to stock-based compensation was approximately $7.0 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Stock options

The Company had granted stock options to directors, key employees and employees. The Company has not granted stock options since 2003 and as of December 31, 2013 and 2012, there were no stock options outstanding.

The Company received cash of $88,000 and $5.7 million from the exercise of stock options for the years ended December 31, 2012 and 2011, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2012 and 2011, was $60,000 and $3.3 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 36,713 shares with a fair value of $1.1 million, 53,888 shares with a fair value of $1.1 million and 55,141 shares with a fair value of $1.1 million issued under this plan during the years ended December 31, 2013, 2012 and 2011, 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, 2013, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2011	2011-2013	254,514
February 2012	2012-2014	251,196
March 2013	2013-2015	244,281

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 2013, 2012 and 2011 were:

	2013	2012	2011
Grant-date fair value	**$29.01**	$17.18	$19.99
Blended volatility range	**16.10% – 19.39%**	24.29% – 25.81%	23.20% – 32.18%
Risk-free interest rate range	**.09% – .40%**	.10% – .35%	.09% – 1.34%
Discounted dividends per share	**$ 2.12**	$ 1.19	$ 1.23

There were no performance shares that vested in 2013, 2012 or 2011.

A summary of the status of the performance share awards for the year ended December 31, 2013, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	786,136	$18.17
Granted	264,614	29.01
Vested	–	–
Forfeited	(300,759)	18.20
Nonvested at end of period	749,991	$21.99

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:

	2013	2012	2011
		(In thousands)	
United States	**$415,202**	$(47,175)	$333,486
Foreign	**416**	1,708	2,740
Income (loss) before income taxes from continuing operations	**$415,618**	$(45,467)	$336,226

Income tax expense (benefit) from continuing operations for the years ended December 31 was as follows:

	2013	2012	2011
		(In thousands)	
Current:			
Federal	**$ 45,518**	$(26,858)	$ (7,188)
State	**4,311**	858	778
Foreign	**(29)**	(75)	127
	49,800	(26,075)	(6,283)
Deferred:			
Income taxes:			
Federal	**78,953**	(1,224)	105,528
State	**8,031**	(6,323)	13,157
Investment tax credit – net	**(206)**	44	240
	86,778	(7,503)	118,925
Change in uncertain tax positions	**–**	1,974	(1,048)
Change in accrued interest	**158**	458	(1,320)
Total income tax expense (benefit)	**$136,736**	$(31,146)	$110,274

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

	2013	2012
	(In thousands)	
Deferred tax assets:		
Regulatory matters	**$ 125,607**	$ 121,781
Accrued pension costs	**74,320**	85,037
Alternative minimum tax credit carryforward	**33,304**	–
Compensation-related	**31,550**	23,441
Asset retirement obligations	**29,578**	26,748
Legal and environmental contingencies	**10,710**	8,046
Other	**45,101**	39,792
Total deferred tax assets	**350,170**	304,845
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**813,597**	755,392
Basis differences on oil and natural gas producing properties	**266,168**	167,113
Regulatory matters	**64,914**	82,077
Intangible asset amortization	**13,579**	14,078
Other	**26,170**	18,441
Total deferred tax liabilities	**1,184,428**	1,037,101
Net deferred income tax liability	**$ (834,258)**	$ (732,256)

As of December 31, 2013 and 2012, no valuation allowance has been recorded associated with the previously identified deferred tax assets. The alternative minimum tax credit carryforwards do not expire.

The following table reconciles the change in the net deferred income tax liability from December 31, 2012, to December 31, 2013, to deferred income tax expense:

	2013
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$102,002**
Deferred taxes associated with other comprehensive loss	**(7,277)**
Other	**(7,947)**
Deferred income tax expense for the period	**$ 86,778**

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,	2013		2012		2011	
	Amount	**%**	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	**$145,466**	**35.0**	$(15,914)	35.0	$117,679	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax	**10,524**	**2.5**	2,469	(5.4)	10,653	3.2
Nonqualified benefit plans	**(5,173)**	**(1.2)**	(2,359)	5.2	(2,918)	(.9)
Depletion allowance	**(3,764)**	**(.9)**	(3,728)	8.2	(3,266)	(1.0)
Federal renewable energy credit	**(3,404)**	**(.8)**	(3,401)	7.5	(3,485)	(1.0)
Deductible K-Plan dividends	**(1,593)**	**(.4)**	(2,829)	6.2	(2,282)	(.7)
AFUDC equity	**(1,074)**	**(.3)**	(1,500)	3.3	(873)	(.3)
Resolution of tax matters and uncertain tax positions	**(859)**	**(.2)**	2,559	(5.6)	(3,906)	(1.2)
Deferred tax rate changes	**741**	**.2**	(3,083)	6.8	(417)	(.1)
Other	**(4,128)**	**(1.0)**	(3,360)	7.3	(911)	(.2)
Total income tax expense (benefit)	**$136,736**	**32.9**	$(31,146)	68.5	$110,274	32.8

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 $7.0 million at December 31, 2013. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2013, was approximately $2.2 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:

	2013	2012	2011
		(In thousands)	
Balance at beginning of year	**$14,914**	$11,206	$ 9,378
Additions for tax positions of prior years	**–**	3,708	4,172
Settlements	**–**	–	(2,344)
Balance at end of year	**$14,914**	$14,914	$11,206

Included in the balance of unrecognized tax benefits at December 31, 2013 and 2012, were $8.4 million and $8.4 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 $9.0 million, including approximately $2.5 million for the payment of interest and penalties at December 31, 2013, and was $8.5 million, including approximately $2.0 million for the payment of interest and penalties at December 31, 2012.

It is likely that substantially all of the unrecognized tax benefits, as well as interest, at December 31, 2013, will be settled in the next twelve months due to the anticipated settlement of federal and state audits.

For the years ended December 31, 2013, 2012 and 2011, the Company recognized approximately $1.2 million, $740,000 and $780,000, respectively, in interest expense. Penalties were not material in 2013, 2012 and 2011. The Company recognized interest income of approximately $660,000, $290,000 and $1.9 million for the years ended December 31, 2013, 2012 and 2011, respectively. The Company had accrued liabilities of approximately $2.8 million and $1.4 million at December 31, 2013 and 2012, respectively, for the payment of interest.

In September 2013, the Internal Revenue Service released final regulations relating to the capitalization of tangible personal property which are effective for tax years beginning on or after January 1, 2014. The Company does not expect these new regulations to have a material effect on its results of operations, financial position or cash flows.

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. 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' 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 and processing facilities primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment is constructing Dakota Prairie Refinery in conjunction with Calumet to refine crude oil and 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/Gulf States regions of the United States.

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, automobile liability and pollution liability coverages. Centennial Capital also owns certain real and personal property. The Other category also includes Centennial Resources' 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:

	2013	2012	2011
		(In thousands)	
External operating revenues:			
Electric	**$ 257,260**	$ 236,895	$ 225,468
Natural gas distribution	**851,945**	754,848	907,400
Pipeline and energy services	**155,369**	139,883	210,846
	1,264,574	1,131,626	1,343,714
Exploration and production	**490,924**	412,651	359,873
Construction materials and contracting	**1,675,444**	1,597,257	1,509,538
Construction services	**1,029,909**	932,013	834,918
Other	**1,553**	1,884	2,449
	3,197,830	2,943,805	2,706,778
Total external operating revenues	**$4,462,404**	$4,075,431	$4,050,492
Intersegment operating revenues:			
Electric	**$ –**	$ –	$ –
Natural gas distribution	**–**	–	–
Pipeline and energy services	**46,699**	53,274	67,497
Exploration and production	**45,099**	35,966	93,713
Construction materials and contracting	**36,693**	20,168	472
Construction services	**9,930**	6,545	19,471
Other	**8,067**	8,486	8,997
Intersegment eliminations	**(146,488)**	(124,439)	(190,150)
Total intersegment operating revenues	**$ –**	$ –	$ –
Depreciation, depletion and amortization:			
Electric	**$ 32,789**	$ 32,509	$ 32,177
Natural gas distribution	**50,031**	45,731	44,641
Pipeline and energy services	**29,119**	27,684	25,502
Exploration and production	**186,458**	160,681	142,645
Construction materials and contracting	**74,470**	79,527	85,459
Construction services	**11,939**	11,063	11,399
Other	**2,050**	2,010	1,572
Total depreciation, depletion and amortization	**$ 386,856**	$ 359,205	$ 343,395

	2013	2012	2011
		(In thousands)	
Interest expense:			
Electric	**$ 12,590**	$ 12,421	$ 13,745
Natural gas distribution	**25,123**	28,726	29,444
Pipeline and energy services	**10,330**	7,742	10,516
Exploration and production	**14,315**	9,018	7,445
Construction materials and contracting	**17,394**	15,211	16,241
Construction services	**4,306**	4,435	4,473
Other	**15**	13	–
Intersegment eliminations	**(156)**	(867)	(510)
Total interest expense	**$ 83,917**	$ 76,699	$ 81,354
Income taxes:			
Electric	**$ 9,683**	$ 8,975	$ 7,242
Natural gas distribution	**16,633**	12,005	16,931
Pipeline and energy services	**3,390**	15,291	12,912
Exploration and production	**53,197**	(108,264)	46,298
Construction materials and contracting	**24,765**	14,099	11,227
Construction services	**29,504**	24,128	13,426
Other	**2,433**	2,620	2,238
Intersegment eliminations	**(2,869)**	–	–
Total income taxes	**$ 136,736**	$ (31,146)	$ 110,274
Earnings (loss) on common stock:			
Electric	**$ 34,837**	$ 30,634	$ 29,258
Natural gas distribution	**37,656**	29,409	38,398
Pipeline and energy services	**7,629**	26,588	23,082
Exploration and production	**94,450**	(177,283)	80,282
Construction materials and contracting	**50,946**	32,420	26,430
Construction services	**52,213**	38,429	21,627
Other	**5,136**	4,797	6,190
Intersegment eliminations	**(4,307)**	–	–
Earnings (loss) on common stock before income (loss) from discontinued operations	**278,560**	(15,006)	225,267
Income (loss) from discontinued operations, net of tax*	**(312)**	13,567	(12,926)
Total earnings (loss) on common stock	**$ 278,248**	$ (1,439)	$ 212,341
Capital expenditures:			
Electric	**$ 168,557**	$ 112,035	$ 52,072
Natural gas distribution	**101,279**	130,178	70,624
Pipeline and energy services	**127,092**	133,787	45,556
Exploration and production	**391,315**	554,528	272,855
Construction materials and contracting	**34,607**	45,083	52,303
Construction services	**15,102**	14,835	9,711
Other	**2,249**	791	18,759
Net proceeds from sale or disposition of property and other	**(112,131)**	(57,460)	(40,857)
Total net capital expenditures	**$ 728,070**	$ 933,777	$ 481,023
Assets:			
Electric**	**$ 884,283**	$ 760,324	$ 672,940
Natural gas distribution**	**1,786,068**	1,703,459	1,679,091
Pipeline and energy services	**798,701**	622,470	526,797
Exploration and production	**1,616,131**	1,539,017	1,481,556
Construction materials and contracting	**1,305,808**	1,371,252	1,374,026
Construction services	**450,614**	429,547	418,519
Other***	**219,727**	256,422	403,196
Total assets	**$7,061,332**	$6,682,491	$6,556,125

	2013	2012	2011
		(In thousands)	
Property, plant and equipment:			
Electric**	**$1,315,822**	$1,150,584	$1,068,524
Natural gas distribution**	**1,776,901**	1,689,950	1,568,866
Pipeline and energy services	**962,172**	816,533	719,291
Exploration and production	**3,060,848**	2,764,560	2,615,146
Construction materials and contracting	**1,510,355**	1,504,981	1,499,852
Construction services	**134,948**	130,624	124,796
Other	**49,997**	50,519	49,747
Eliminations	**(7,177)**	–	–
Less accumulated depreciation, depletion and amortization	**3,872,487**	3,608,912	3,361,208
Net property, plant and equipment	**$4,931,379**	$4,498,839	$4,285,014

* 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 impairments of the coalbed natural gas gathering assets of $9.0 million (after tax) and $1.7 million (after tax) in 2013 and 2012, respectively, and the reversal of the natural gas gathering arbitration charge of $1.5 million (after tax) and $15.0 million (after tax) in 2013 and 2012, respectively, as discussed in Notes 1 and 19, respectively, 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 2013, 2012 and 2011 include noncash capital expenditure-related accounts payable and exclude capital expenditures of the noncontrolling interest related to Dakota Prairie Refinery. The net transactions were $(56.8) million in 2013, $33.7 million in 2012 and $24.0 million in 2011.

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. In 2010, all benefit and service accruals for nonunion and certain union plans were frozen. In 2011 and 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 at certain of the Company's businesses.

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, 2013 and 2012, and amounts recognized in the Consolidated Balance Sheets at December 31, 2013 and 2012, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	**2013**	2012
		(In thousands)		
Change in benefit obligation:				
Benefit obligation at beginning of year	**$459,111**	$ 435,618	**$103,358**	$ 110,689
Service cost	**155**	1,078	**1,675**	1,747
Interest cost	**16,249**	17,598	**3,215**	4,166
Plan participants' contributions	**–**	–	**1,472**	2,688
Amendments	**–**	–	**–**	(11,418)
Actuarial (gain) loss	**(44,551)**	30,939	**(20,985)**	3,469
Benefits paid	**(28,192)**	(26,122)	**(7,009)**	(7,983)
Benefit obligation at end of year	**402,772**	459,111	**81,726**	103,358
Change in net plan assets:				
Fair value of plan assets at beginning of year	**309,184**	278,000	**74,361**	68,085
Actual gain on plan assets	**35,539**	34,493	**13,819**	6,497
Employer contribution	**18,313**	22,813	**1,900**	5,074
Plan participants' contributions	**–**	–	**1,472**	2,688
Benefits paid	**(28,192)**	(26,122)	**(7,009)**	(7,983)
Fair value of net plan assets at end of year	**334,844**	309,184	**84,543**	74,361
Funded status – (under) over	**$ (67,928)**	$(149,927)	**$ 2,817**	$ (28,997)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	**$ –**	$ –	**$ 9,679**	$ –
Other accrued liabilities (current)	**–**	–	**(381)**	(655)
Other liabilities (noncurrent)	**(67,928)**	(149,927)	**(6,481)**	(28,342)
Net amount recognized	**$ (67,928)**	$(149,927)	**$ 2,817**	$ (28,997)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	**$135,061**	$ 202,406	**$ 11,314**	$ 43,589
Prior service cost (credit)	**365**	437	**(17,137)**	(18,594)
Total	**$135,426**	$ 202,843	**$ (5,823)**	$ 24,995

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 pension plans all have accumulated benefit obligations in excess of plan assets. The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for these plans at December 31 were as follows:

	2013	2012
	(In thousands)	
Projected benefit obligation	**$402,772**	$459,111
Accumulated benefit obligation	**$402,772**	$459,111
Fair value of plan assets	**$334,844**	$309,184

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		
	2013	2012	2011	**2013**	2012	2011
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	**$ 155**	$ 1,078	$ 2,252	**$ 1,675**	$ 1,747	$ 1,443
Interest cost	**16,249**	17,598	19,500	**3,215**	4,166	4,700
Expected return on assets	**(19,917)**	(23,536)	(22,809)	**(4,343)**	(4,890)	(5,051)
Amortization of prior service cost (credit)	**71**	(46)	45	**(1,457)**	(1,438)	(2,677)
Recognized net actuarial loss	**7,173**	7,070	4,656	**1,814**	2,134	753
Curtailment loss (gain)	**–**	(1,023)	1,218	**–**	–	–
Amortization of net transition obligation	**–**	–	–	**–**	2,128	2,125
Net periodic benefit cost, including amount capitalized	**3,731**	1,141	4,862	**904**	3,847	1,293
Less amount capitalized	**727**	937	1,196	**164**	910	(50)
Net periodic benefit cost	**3,004**	204	3,666	**740**	2,937	1,343
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	**(60,173)**	19,982	76,310	**(30,461)**	1,863	23,863
Prior service credit	**–**	–	–	**–**	(11,418)	–
Amortization of actuarial loss	**(7,173)**	(7,070)	(4,656)	**(1,814)**	(2,134)	(753)
Amortization of prior service (cost) credit	**(71)**	1,069	(1,263)	**1,457**	1,438	2,677
Amortization of net transition obligation	**–**	–	–	**–**	(2,128)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	**(67,417)**	13,981	70,391	**(30,818)**	(12,379)	23,662
Total recognized in net periodic benefit cost and accumulated other comprehensive (income) loss	**$(64,413)**	$ 14,185	$ 74,057	**$(30,078)**	$ (9,442)	$25,005

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 2014 are $4.8 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 2014 are $793,000 and $1.4 million, respectively. Prior service cost is amortized on a straight line basis over the average remaining service period of active participants.

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

	Pension Benefits		Other Postretirement Benefits	
	2013	2012	**2013**	2012
Discount rate	**4.53%**	3.65%	**4.48%**	3.67%
Expected return on plan assets	**7.00%**	7.00%	**6.00%**	6.00%
Rate of compensation increase	**N/A**	N/A	**3.00%**	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	
	2013	2012	**2013**	2012
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%

* Effective September 30, 2012, all benefit and service accruals for a union plan were frozen. Compensation increases had previously been frozen for all other plans.

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:

	2013	2012
Health care trend rate assumed for next year	**6.0% – 7.0%**	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, 2013:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 159	$ (135)
Effect on postretirement benefit obligation	$3,352	$(2,920)

The Company's pension assets are managed by 16 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 plans' 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 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, 2013 and 2012, there were no transfers between Levels 1 and 2.

The fair value of the Company's pension plans' assets (excluding cash) by class were as follows:

	Fair Value Measurements at December 31, 2013, 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, 2013
		(In thousands)		
Assets:				
Cash equivalents	$ –	$ 9,406	$ –	$ 9,406
Equity securities:				
U.S. companies	62,599	–	–	62,599
International companies	39,437	–	–	39,437
Collective and mutual funds*	116,265	42,483	–	158,748
Corporate bonds	–	42,721	–	42,721
Municipal bonds	–	7,561	–	7,561
U.S. Treasury securities	7,487	4,335	–	11,822
Total assets measured at fair value	$225,788	$106,506	$ –	$332,294

* Collective and mutual funds invest approximately 11 percent in common stock of mid-cap U.S. companies, 34 percent in common stock of large-cap U.S. companies, 11 percent in U.S. Treasuries, 27 percent in corporate bonds and 17 percent in other investments.

The fair value of the Company's pension plans' assets by class were 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.

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

The estimated fair value of the other postretirement benefit plans' 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 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 other postretirement benefit plans' Level 2 insurance 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, 2013 and 2012, there were no transfers between Levels 1 and 2.

The fair value of the Company's other postretirement benefit plans' assets (excluding cash) by asset class were as follows:

	Fair Value Measurements at December 31, 2013, 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, 2013
		(In thousands)		
Assets:				
Cash equivalents	$ –	$ 2,142	$ –	$ 2,142
Equity securities:				
U.S. companies	2,802	–	–	2,802
International companies	221	–	–	221
Insurance contract*	–	79,374	–	79,374
Total assets measured at fair value	$3,023	$81,516	$ –	$84,539

* The insurance contract invests approximately 55 percent in common stock of large-cap U.S. companies, 12 percent in U.S. Treasuries, 8 percent in mortgage-backed securities, 8 percent in common stock of mid-cap U.S. companies, 9 percent in corporate bonds and 8 percent in other investments.

The fair value of the Company's other postretirement benefit plans' assets by asset class were 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 contract*	–	68,850	–	68,850
Total assets measured at fair value	$3,520	$70,841	$ –	$74,361

* The insurance 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.

The Company expects to contribute approximately $32.5 million to its defined benefit pension plans and approximately $1.5 million to its postretirement benefit plans in 2014.

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)	
2014	$ 23,391	$ 5,596	$237
2015	23,645	5,584	230
2016	23,911	5,583	221
2017	24,439	5,543	211
2018	24,814	5,483	200
2019 – 2023	130,026	26,038	823

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's net periodic benefit cost for these plans was $7.3 million, $8.1 million and $8.1 million in 2013, 2012 and 2011, respectively. The total projected benefit obligation for these plans was $106.9 million and $113.0 million at December 31, 2013 and 2012, respectively. The accumulated benefit obligation for these plans was $99.7 million and $107.5 million at December 31, 2013 and 2012, respectively. A weighted average discount rate of 4.32 percent and 3.44 percent at December 31, 2013 and 2012, respectively, and a rate of compensation increase of 4.00 percent and 3.00 percent at December 31, 2013 and 2012, were used to determine benefit obligations. A discount rate of 3.44 percent and 4.00 percent at December 31, 2013 and 2012, respectively, and a rate of compensation increase of 3.00 percent and 4.00 percent at December 31, 2013 and 2012, 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 2014; $6.7 million in 2015; $6.5 million in 2016; $6.7 million in 2017; $7.2 million in 2018 and $37.5 million for the years 2019 through 2023.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Costs incurred under this plan for 2013 and 2012 were $304,000 and $84,000, respectively.

The Company had investments of $98.1 million and $84.4 million at December 31, 2013 and 2012, respectively, consisting of equity securities of $53.5 million and $41.9 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $31.4 million and $32.7 million, respectively, and other investments of $13.2 million and $9.8 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees and the costs incurred under these plans were $33.2 million in 2013, $29.3 million in 2012 and $27.1 million in 2011.

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 2013 and 2012 is for the plan's year-end at December 31, 2012, and December 31, 2011, 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 2013	Pension Protection Act Zone Status 2012	FIP/RP Status Pending/ Implemented	Contributions 2013	Contributions 2012	Contributions 2011	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
						(In thousands)			
Edison Pension Plan	93-6061681-001	Green as of 12/31/2013	Green as of 12/31/2012	No	**$ 6,358**	$ 5,171	$ 2,700	No	12/31/2014
IBEW Local 38 Pension Plan	34-6574238-001	Yellow as of 4/30/2013	Yellow as of 4/30/2012	Implemented	**1,041**	2,771	1,469	No	4/27/2014
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2013	Red as of 6/30/2012	Implemented	**1,284**	1,093	1,331	No	11/30/2014
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2013	Red as of 2/29/2012	Implemented	**1,489**	564	722	No	8/31/2015
Laborers Pension Trust Fund for Northern California	94-6277608-001	Yellow as of 5/31/2013	Yellow as of 5/31/2012	Implemented	**921**	567	628	No	6/30/2016
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**5,883**	5,603	4,841	No	5/31/2012*–8/31/2017
OE Pension Trust Fund	94-6090764-001	Yellow	Yellow as of 12/31/2012	Implemented	**1,510**	1,156	1,367	No	6/30/2013*–3/31/2016
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming	83-6011320-001	Red as of 12/31/2013	Red as of 12/31/2012	Implemented	**76**	91	96	No	10/31/2005*
Operating Engineers Pension Trust	95-6032478-001	Red as of 6/30/2013	Red as of 6/30/2012	Implemented	**493**	761	458	No	7/1/2013*–7/20/2014
Pension and Retirement Plan of Plumbers and Pipefitters Union Local No. 525	88-6003864-001	Green as of 6/30/2012	Green as of 6/30/2011	No	**1,657**	1,202	759	No	5/31/2010*
Sheet Metal Workers' Pension Plan of Southern CA, AZ and NV	95-6052257-001	Red as of 12/31/2013	Red as of 12/31/2012	Implemented	**512**	467	336	No	6/30/2014
Other funds					**18,036**	15,333	14,451		
Total contributions					**$39,260**	$34,779	$29,158		

* 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)
Edison Pension Plan	2012 and 2011
IBEW Local 38 Pension Plan	2012 and 2011
IBEW Local No. 82 Pension Plan	2012 and 2011
Local Union No. 124 IBEW Pension Trust Fund	2012 and 2011
Local Union 212 IBEW Pension Trust Fund	2012 and 2011
IBEW Local Union No. 357 Pension Plan A	2012 and 2011
IBEW Local 648 Pension Plan	2012 and 2011
Idaho Plumbers and Pipefitters Pension Plan	2012 and 2011
Minnesota Teamsters Construction Division Pension Fund	2012 and 2011
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming	2012 and 2011
Pension and Retirement Plan of Plumbers and Pipefitters Union Local No. 525	2012 and 2011

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 $37.1 million, $31.4 million and $24.0 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Amounts contributed in 2013, 2012 and 2011 to defined contribution multiemployer plans were $20.6 million, $18.7 million and $15.3 million, respectively.

Note 17 – Jointly Owned Facilities

The consolidated financial statements include the Company's ownership interests in the assets, liabilities and expenses of the Big Stone Station, Coyote Station and Wygen III. 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:

	2013	2012
	(In thousands)	
Big Stone Station:		
Utility plant in service	**$ 63,890**	$ 63,146
Less accumulated depreciation	**41,323**	40,859
	$ 22,567	$ 22,287
Coyote Station:		
Utility plant in service	**$138,261**	$135,073
Less accumulated depreciation	**89,528**	87,524
	$ 48,733	$ 47,549
Wygen III:		
Utility plant in service	**$ 64,332**	$ 63,462
Less accumulated depreciation	**4,639**	3,368
	$ 59,693	$ 60,094

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, an 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. On April 12, 2013, the MTPSC issued an interim order authorizing an interim increase of $850,000 annually to be effective with service rendered on or after April 15, 2013, subject to refund. A hearing was held August 5-6, 2013. On December 5, 2013, Montana-Dakota and the Montana Consumer Counsel filed a stipulation with the MTPSC with an increase of $1.5 million annually. On December 12, 2013, the MTPSC approved the stipulation to be effective with service rendered on or after December 15, 2013.

On February 11, 2013, Montana-Dakota filed an application with the NDPSC for approval of an environmental cost recovery rider for recovery of Montana-Dakota's share of the costs resulting from the environmental retrofit required to be installed at the Big Stone Station. The costs proposed to be recovered are associated with the ongoing construction costs for the installation of the BART air-quality control system. On February 27, 2013, the NDPSC suspended the filing pending further review. On May 31, 2013, Montana-Dakota filed revisions to its filing to reflect revised budget amounts. A hearing was held on September 16, 2013. On December 18, 2013, the NDPSC approved the environmental cost recovery rider tariff and adjustment.

On September 18, 2013, Montana-Dakota filed an application with the NDPSC for a natural gas rate increase. Montana-Dakota requested a total increase of $6.8 million annually or approximately 6.4 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, an operations building, automated meter reading and a new customer billing system. Montana-Dakota requested an interim increase, subject to refund, of $4.5 million or approximately 4.2 percent. On October 9, 2013, the NDPSC approved the interim increase to be effective with service rendered on or after November 17, 2013. On October 23, 2013, Montana-Dakota and the NDPSC Advocacy Staff filed a settlement agreement that resolved the revenue requirement portion of the application and reflected a natural gas rate increase of $4.3 million annually or approximately 4.0 percent, and agreed that Montana-Dakota will only implement $4.3 million of interim rate relief. The NDPSC held an informal hearing on the settlement on November 13, 2013. Montana-Dakota implemented the interim rate increase of $4.3 million effective with service rendered on or after November 17, 2013. On December 30, 2013, the NDPSC approved the settlement on the revenue requirement. A hearing on the rate design portion of the case was held February 5, 2014.

On October 31, 2013, WBI Energy Transmission filed a general natural gas rate change application with the FERC for an increase of $28.9 million annually to cover increased investments of $312 million, increased operating costs, and the effect of lower storage and off system volumes. WBI Energy Transmission will begin collecting the requested rates effective May 1, 2014, subject to refund.

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, in some circumstances, an estimate of the possible loss. The Company had accrued liabilities of $29.5 million and $22.5 million for contingencies, including litigation, production taxes, royalty claims and environmental matters as of December 31, 2013 and 2012, respectively, which include 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. The New York Supreme Court granted CEM's petition to vacate the arbitration award on November 20, 2012, and entered an order and judgment to that effect on June 5, 2013. LPP appealed the order and judgment and on February 20, 2014, the New York Supreme Court Appellate Division ruled the arbitration award was properly vacated. 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. 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. 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 was largely reflected in operation and maintenance expense on the Consolidated Statements 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 which was denied on July 22, 2013. On remand of the matter to the Colorado State District Court, SourceGas may 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. The parties subsequently settled the breach of contract claim and, subject to final determination on liability, stipulated to the damages on the common carrier claim, for amounts that are not material. A trial on the common carrier claim was held during July 2013, but a decision has not been issued.

Exploration and Production During the ordinary course of its business, Fidelity is subject to audit for various production related taxes by certain state and federal tax authorities for varying periods as well as claims for royalty obligations under lease agreements for oil and gas production. Disputes may exist regarding facts and questions of law relating to the tax and royalty obligations.

On May 15, 2013, Austin Holdings, LLC filed an action against Fidelity in Wyoming State District Court alleging Fidelity violated the Wyoming Royalty Payment Act and implied lease covenants by deducting production costs from and by failing to properly report and pay royalties for coalbed methane gas production in Wyoming. The plaintiff, in addition to declaratory and injunctive relief, seeks class certification for similarly situated persons and an unspecified amount of monetary damages on behalf of the class for unpaid royalties, interest, reporting violations and attorney fees. Fidelity believes it has meritorious defenses against class certification and the claims.

The Company also is subject to other litigation, and actual and potential claims in the ordinary course of its business which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. Accruals are based on the best information available but actual losses in future periods are affected by various factors making them uncertain. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above issues and other probable and reasonably possible losses in excess of the amounts accrued, while uncertain, 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. In January 2013, the OPUC approved Cascade's application to defer environmental remediation costs at the Eugene site for a period of 12 months starting November 30, 2012. Cascade received an order reauthorizing the deferred accounting for the 12 months starting November 30, 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. 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 of Superfund sites. Cascade has entered into an administrative settlement agreement and consent order with the EPA regarding the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $12.0 million for the remedial investigation, feasibility study and 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 and entered into agreement with 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.

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, 2013, were $32.8 million in 2014, $26.6 million in 2015, $22.2 million in 2016, $17.8 million in 2017, $13.5 million in 2018 and $45.7 million thereafter. Rent expense was $48.1 million, $42.9 million and $40.7 million for the years ended December 31, 2013, 2012 and 2011, respectively.

Purchase commitments

The Company has entered into various commitments, largely construction, natural gas and coal supply, purchased power, natural gas transportation and storage, service, shipping and construction materials supply contracts, some of which are subject to variability in volume and price. These commitments range from one to 47 years. The commitments under these contracts as of December 31, 2013, were $635.8 million in 2014, $281.6 million in 2015, $170.7 million in 2016, $100.3 million in 2017, $73.4 million in 2018 and $910.8 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, 2013, 2012 and 2011, were $861.8 million, $718.4 million and $626.3 million, respectively.

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 agreement obligations. There is no fixed maximum amount guaranteed in relation to the oil and natural gas swap agreements as the amount of the obligation is dependent upon oil and natural gas commodity prices. The amount of derivative activity entered into by the subsidiary is limited by corporate policy. The guarantees of the oil and natural gas swap agreements at December 31, 2013, expire in the years ranging from 2014 to 2015; however, Fidelity continues to enter into additional derivative instruments and, as a result, WBI Holdings from time to time may issue additional guarantees on these derivative instruments. The amount outstanding by Fidelity was $4.8 million and was reflected on the Consolidated Balance Sheet at December 31, 2013. 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, 2013, the fixed maximum amounts guaranteed under these agreements aggregated $54.4 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $32.5 million in 2014; $2.1 million in 2015; $700,000 in 2016; $600,000 in 2017; $500,000 in 2018; $500,000 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 $200,000 and was reflected on the Consolidated Balance Sheet at December 31, 2013. 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, 2013, the fixed maximum amounts guaranteed under these letters of credit, aggregated $36.0 million and are scheduled to expire in 2014. There were no amounts outstanding under the above letters of credit at December 31, 2013.

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, 2013, 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 $800,000. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at December 31, 2013, 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, 2013.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries. 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, 2013, approximately $516 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Variable interest entities

The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary. For more information, see Note 1.

Dakota Prairie Refining, LLC On February 7, 2013, WBI Energy and Calumet formed a limited liability company, Dakota Prairie Refining, and entered into an operating agreement to develop, build and operate Dakota Prairie Refinery in southwestern North Dakota. WBI Energy and Calumet each have a 50 percent ownership interest in Dakota Prairie Refining. WBI Energy's and Calumet's capital commitments, based on a total project cost of $300 million, under the agreement are $150 million and $75 million, respectively. Capital commitments in excess of $300 million are expected to be shared equally between WBI Energy and Calumet. The total project cost is currently estimated at $350 million. Dakota Prairie Refining entered into a term loan for project debt financing of $75 million on April 22, 2013. The operating agreement provides for allocation of profits and losses consistent with ownership interests; however, deductions attributable to project financing debt will be allocated to Calumet. Calumet's future cash distributions from Dakota Prairie Refining will be decreased by the principal and interest to be paid on the project debt, while the cash distributions to WBI Energy will not be decreased. Pursuant to the operating agreement, Centennial agreed to guarantee Dakota Prairie Refining's obligation under the term loan.

Dakota Prairie Refining has been determined to be a VIE, and the Company has determined that it is the primary beneficiary as it has an obligation to absorb losses that could be potentially significant to the VIE through WBI Energy's equity investment and Centennial's guarantee of the third-party term loan. Accordingly, the Company consolidates Dakota Prairie Refining in its financial statements and records a noncontrolling interest for Calumet's ownership interest.

Construction of Dakota Prairie Refinery began in early 2013 and the plant is not yet operational. Therefore, the results of operations of Dakota Prairie Refining did not have a material effect on the Company's Consolidated Statements of Income. The assets of Dakota Prairie Refining shall be used solely for the benefit of Dakota Prairie Refining. The total assets and liabilities of Dakota Prairie Refining reflected on the Company's Consolidated Balance Sheets at December 31 were as follows:

	2013
	(In thousands)
Assets	
Current assets:	
Cash and cash equivalents	$ 4,774
Other current assets	26
Total current assets	4,800
Net property, plant and equipment	172,073
Total assets	$176,873
Liabilities	
Current liabilities:	
Long-term debt due within one year	$ 3,000
Accounts payable	8,904
Taxes payable	5
Accrued compensation	26
Other accrued liabilities	461
Total current liabilities	12,396
Long-term debt	72,000
Total liabilities	$ 84,396

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 expiring in May 2016. The new agreement provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station 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. Although the Company has determined that Coyote Creek is a VIE, the Company has concluded that it is not the primary beneficiary of Coyote Creek because the authority to direct the activities of the entity is 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, 2013, 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 VIE, based on the Company's ownership percentage, at December 31, 2013, was $7.7 million.

Note 20 – Subsequent Event

On January 28, 2014, the Company entered into a note purchase agreement. The Company contracted to issue $50.0 million and $100.0 million of Senior Notes under the agreement on April 15, 2014 and July 15, 2014, respectively, with due dates ranging from July 2024 to April 2044 at a weighted average interest rate of 4.6 percent.

On December 12, 2013, MDU Energy Capital entered into a note purchase agreement. MDU Energy Capital contracted to issue $30.0 million of Senior Notes under the agreement on January 27, 2014, with due dates ranging from January 2029 to January 2044 at a weighted average interest rate of 5.3 percent.

On February 10, 2014, the Company entered into an agreement to purchase working interests and leasehold positions in oil and natural gas production assets in the southern Powder River Basin of Wyoming for approximately $183.0 million, subject to accounting and purchase price adjustments customary with acquisitions of this type. The effective date of the acquisition is October 1, 2013, with the expected closing date to occur on or before April 1, 2014, conditioned upon completing a due diligence process, including environmental reviews, and satisfying other standard closing conditions.

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2013 and 2012:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2013				
Operating revenues	**$931,604**	**$1,060,595**	**$1,285,782**	**$1,184,423**
Operating expenses	**827,073**	**969,217**	**1,135,909**	**1,037,306**
Operating income	**104,531**	**91,378**	**149,873**	**147,117**
Income from continuing operations	**56,592**	**46,392**	**84,550**	**91,348**
Loss from discontinued operations, net of tax	**(77)**	**(59)**	**(118)**	**(58)**
Net income attributable to the Company	**56,515**	**46,512**	**84,456**	**91,450**
Earnings per common share – basic:				
Earnings before discontinued operations	**.30**	**.25**	**.45**	**.48**
Discontinued operations, net of tax	**–**	**–**	**–**	**–**
Earnings per common share – basic	**.30**	**.25**	**.45**	**.48**
Earnings per common share – diluted:				
Earnings before discontinued operations	**.30**	**.24**	**.44**	**.48**
Discontinued operations, net of tax	**–**	**–**	**–**	**–**
Earnings per common share – diluted	**.30**	**.24**	**.44**	**.48**
Weighted average common shares outstanding:				
Basic	**188,831**	**188,831**	**188,831**	**188,929**
Diluted	**189,222**	**189,463**	**189,638**	**189,766**
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) attributable to the Company	35,790	54,113	(29,671)	(60,986)
Earnings 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

Notes:

- First quarter 2013 reflects an unrealized loss on commodity derivatives of $3.7 million (after tax). First quarter 2012 reflects an unrealized loss on commodity derivatives of $2.6 million (after tax).
- Second quarter 2013 reflects an impairment of coalbed natural gas gathering assets of $9.0 million (after tax) and an unrealized gain on commodity derivatives of $8.2 million (after tax). Second quarter 2012 reflects a net benefit of $15.0 million (after tax) related to natural gas gathering operations litigation, a net benefit largely related to estimated insurance recoveries related to the guarantee of a construction contract (reflected in income (loss) from discontinued operations), an unrealized gain on commodity derivatives of $3.0 million (after tax) and an impairment of coalbed natural gas gathering assets of $1.7 million (after tax). For more information, see Notes 1 and 19.
- Third quarter 2013 reflects an unrealized loss on commodity derivatives of $7.9 million (after tax). Third quarter 2012 reflects a $100.9 million (after tax) noncash write-down of oil and natural gas properties and an unrealized loss on commodity derivatives of $700,000 (after tax). For more information, see Note 1.
- Fourth quarter 2013 reflects a net benefit of $1.5 million (after tax) related to natural gas gathering operations litigation and an unrealized loss on commodity derivatives of $500,000 (after tax). Fourth quarter 2012 reflects a $145.9 million (after tax) noncash write-down of oil and natural gas properties, 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 (reflected in income (loss) from discontinued operations), as well as an unrealized loss on commodity derivatives of $200,000 (after tax). For more information, see Notes 1 and 19.

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:

	2013	2012	2011
		(In thousands)	
Subject to amortization	**$2,893,010**	$2,531,562	$2,345,114
Not subject to amortization	**124,869**	191,794	232,462
Total capitalized costs	**3,017,879**	2,723,356	2,577,576
Less accumulated depreciation, depletion and amortization	**1,562,116**	1,383,386	1,229,654
Net capitalized costs	**$1,455,763**	$1,339,970	$1,347,922

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,	**2013***	2012*	2011*
		(In thousands)	
Acquisitions:			
Proved properties	**$ 1,817**	$ 839	$ 3,999
Unproved properties	**4,608**	31,109	63,354
Exploration	**26,975**	235,906	41,775
Development	**355,421**	275,959	161,647
Total capital expenditures	**$388,821**	$543,813	$270,775

* 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 $(10.7) million, $(200,000) and $(1.8) million for the years ended December 31, 2013, 2012 and 2011, respectively.

The preceding table excludes proceeds from the sales of oil and natural gas properties of $83.6 million, $6.0 million and $12.4 million for the years ended December 31, 2013, 2012 and 2011, 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,	**2013**	2012	2011
		(In thousands)	
Revenues:			
Sales to affiliates	**$ 45,099**	$ 35,966	$ 93,713
Sales to external customers	**497,018**	379,647	348,428
Realized gain on commodity derivatives	**173**	33,628	9,618
Unrealized gain (loss) on commodity derivatives	**(6,267)**	(624)	1,827
Production costs	**144,136**	134,795	140,606
Depreciation, depletion and amortization*	**182,352**	157,078	139,539
Write-downs of oil and natural gas properties	**–**	391,800	–
Pretax income (loss)	**209,535**	(235,056)	173,441
Income tax expense (benefit)	**75,836**	(88,612)	63,655
Results of operations for producing activities	**$133,699**	$(146,444)	$109,786

* Includes accretion of discount for asset retirement obligations of $3.6 million, $3.3 million and $3.6 million for the years ended December 31, 2013, 2012 and 2011, 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, 2013, 2012 and 2011, were calculated using SEC Defined Prices. Other factors used in the proved reserve estimates are current estimates of well operating and future development costs (which include asset retirement 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, 2013, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	33,453	7,153	239,278	80,486
Production	(4,815)	(781)	(28,008)	(10,264)
Extensions and discoveries	13,313	1,333	26,428	19,050
Improved recovery	–	–	–	–
Purchases of proved reserves	–	–	–	–
Sales of proved reserves	(1,286)	(25)	(40,055)	(7,987)
Revisions of previous estimates	354	(1,078)	802	(590)
Balance at end of year	41,019	6,602	198,445	80,695

Significant changes in proved reserves for the year ended December 31, 2013, include:

- Extensions and discoveries of 19.1 MMBOE, primarily due to drilling activity and new PUD locations at the Company's Bakken and Paradox Basin properties, as well as new PUD locations at Big Horn and East Texas
- Sales of proved reserves of (8.0) MMBOE, primarily at the Company's Green River Basin property

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 following table summarizes the breakdown of the Company's proved reserves between proved developed and PUD reserves at December 31:

	2013	2012	2011
Proved developed reserves:			
Oil (MBbls)	**31,394**	27,412	23,653
NGL (MBbls)	**5,322**	5,342	5,225
Natural Gas (MMcf)	**176,546**	218,259	303,495
Total (MBOE)	**66,140**	69,131	79,460
PUD reserves:			
Oil (MBbls)	**9,625**	6,041	3,352
NGL (MBbls)	**1,280**	1,811	2,117
Natural Gas (MMcf)	**21,899**	21,019	76,332
Total (MBOE)	**14,555**	11,355	18,191
Total proved reserves:			
Oil (MBbls)	**41,019**	33,453	27,005
NGL (MBbls)	**6,602**	7,153	7,342
Natural Gas (MMcf)	**198,445**	239,278	379,827
Total (MBOE)	**80,695**	80,486	97,651

As of December 31, 2013, the Company had 14.6 MMBOE of PUD reserves, which is an increase of 3.2 MMBOE from December 31, 2012. The increase relates to the Company adding 11.9 MMBOE of new PUD reserves, primarily in the Company's oil properties. This was partially offset by the Company converting 7.1 MMBOE, requiring $127.3 million of drilling and completion capital in 2013 and PUD revision of (1.6) MMBOE. At December 31, 2013, 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, 2013, are $143.6 million in 2014, $116.0 million in 2015 and $18.1 million in 2016.

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:

	2013	2012	2011
		(In thousands)	
Future cash inflows	**$4,507,000**	$3,696,200	$4,188,000
Future production costs	**1,734,800**	1,536,500	1,560,300
Future development costs	**403,000**	301,600	285,300
Future net cash flows before income taxes	**2,369,200**	1,858,100	2,342,400
Future income tax expense	**545,200**	304,900	531,100
Future net cash flows	**1,824,000**	1,553,200	1,811,300
10% annual discount for estimated timing of cash flows	**810,000**	669,800	832,500
Discounted future net cash flows relating to proved oil, NGL and natural gas reserves	**$1,014,000**	$ 883,400	$ 978,800

The following are the sources of change in the standardized measure of discounted future net cash flows by year:

	2013	2012	2011
		(In thousands)	
Beginning of year	**$ 883,400**	$ 978,800	$ 896,100
Net revenues from production	**(398,000)**	(280,800)	(301,500)
Net change in sales prices and production costs related to future production	**162,200**	(406,300)	82,300
Extensions and discoveries, net of future production-related costs	**366,500**	355,300	226,300
Improved recovery, net of future production-related costs	**–**	–	–
Purchases of proved reserves, net of future production-related costs	**–**	–	9,500
Sales of proved reserves	**(37,800)**	(2,600)	–
Changes in estimated future development costs	**6,700**	37,600	51,100
Development costs incurred during the current year	**141,500**	77,700	56,300
Accretion of discount	**94,600**	121,400	105,000
Net change in income taxes	**(141,400)**	110,000	(55,800)
Revisions of previous estimates	**(55,800)**	(100,700)	(92,900)
Other	**(7,900)**	(7,000)	2,400
Net change	**130,600**	(95,400)	82,700
End of year	**$1,014,000**	$ 883,400	$ 978,800

The estimated discounted future cash inflows from estimated future production of proved reserves were computed using prices as previously discussed. Future production and development costs, which include asset retirement 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 to the estimated net future pretax cash flows less the tax basis of the oil and gas properties, adjusted for permanent differences and tax credits.

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, 2013, 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 third 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, third and fifth 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, 2013, 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)	749,991 (2)	$21.99	6,176,556 (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 175,758 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

FORM 10-K

MDU RESOURCES GROUP, INC.
Schedule I – Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Income and Comprehensive Income

Years ended December 31,	**2013**	2012	2011
		(In thousands)	
Operating revenues	**$549,239**	$472,302	$518,268
Operating expenses	**473,917**	405,095	450,579
Operating income	**75,322**	67,207	67,689
Other income	**3,709**	3,925	2,710
Interest expense	**17,386**	17,297	18,660
Income before income taxes	**61,645**	53,835	51,739
Income taxes	**13,520**	11,798	10,476
Equity in earnings (loss) of subsidiaries	**230,808**	(42,791)	171,763
Net income (loss) attributable to the Company	**278,933**	(754)	213,026
Dividends declared on preferred stocks	**685**	685	685
Earnings (loss) on common stock	**$278,248**	$ (1,439)	$212,341
Comprehensive income (loss)	**$289,449**	$ (2,474)	$197,286

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,	2013	2012
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 5,051	$ 3,596
Receivables, net	88,529	89,238
Accounts receivable from subsidiaries	31,372	2,957
Inventories	29,312	41,469
Deferred income taxes	3,196	3,685
Prepayments and other current assets	14,231	9,120
Total current assets	171,691	150,065
Investments	60,687	52,123
Investment in subsidiaries	2,380,829	2,253,294
Property, plant and equipment	1,785,861	1,581,776
Less accumulated depreciation, depletion and amortization	660,693	621,623
Net property, plant and equipment	1,125,168	960,153
Deferred charges and other assets:		
Goodwill	4,812	4,812
Other	121,253	155,483
Total deferred charges and other assets	126,065	160,295
Total assets	$3,864,440	$3,575,930
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	$ 109	$ 108
Accounts payable	45,282	42,149
Accounts payable to subsidiaries	4,839	6,423
Taxes payable	12,337	12,399
Dividends payable	33,737	171
Accrued compensation	16,076	10,282
Other accrued liabilities	28,042	29,490
Total current liabilities	140,422	101,022
Long-term debt	434,598	356,760
Deferred credits and other liabilities:		
Deferred income taxes	205,639	172,769
Other liabilities	260,617	297,131
Total deferred credits and other liabilities	466,256	469,900
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 – 189,868,780 shares in 2013 and 189,369,450 shares in 2012	189,869	189,369
Other paid-in capital	1,056,996	1,039,080
Retained earnings	1,603,130	1,457,146
Accumulated other comprehensive loss	(38,205)	(48,721)
Treasury stock at cost – 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,808,164	2,633,248
Total stockholders' equity	2,823,164	2,648,248
Total liabilities and stockholders' equity	$3,864,440	$3,575,930

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,	**2013**	2012	2011
		(In thousands)	
Net cash provided by operating activities	**$ 188,259**	$ 225,968	$ 217,514
Investing activities:			
Capital expenditures	**(211,013)**	(150,337)	(74,580)
Net proceeds from sale or disposition of property and other	**20,624**	1,120	720
Investments in and advances to subsidiaries	**(1,016)**	(1,387)	(5,701)
Investments from and advances from subsidiaries	**10,000**	5,000	–
Investments	**613**	12	–
Net cash used in investing activities	**(180,792)**	(145,592)	(79,561)
Financing activities:			
Repayment of short-term borrowings	**–**	–	(20,000)
Issuance of long-term debt	**77,924**	76,000	–
Repayment of long-term debt	**(85)**	(21)	(107)
Proceeds from issuance of common stock	**14,554**	88	5,744
Dividends paid	**(98,405)**	(159,768)	(123,323)
Excess tax benefit on stock-based compensation	**–**	21	358
Net cash used in financing activities	**(6,012)**	(83,680)	(137,328)
Increase (decrease) in cash and cash equivalents	**1,455**	(3,304)	625
Cash and cash equivalents – beginning of year	**3,596**	6,900	6,275
Cash and cash equivalents – end of year	**$ 5,051**	$ 3,596	$ 6,900

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 $434.7 million at December 31, 2013, with annual maturities of $100,000 in 2014, $100,000 in 2015, $50.1 million in 2016, $79.0 million in 2017, $100.0 million in 2018 and $205.4 million scheduled to mature in years after 2018.

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 $77.6 million, $125.8 million and $96.1 million for the years ended December 31, 2013, 2012 and 2011, respectively.

MDU RESOURCES GROUP, INC.
Schedule II – Consolidated Valuation and Qualifying Accounts
For the years ended December 31, 2013, 2012 and 2011

		Additions			
Description	Balance at Beginning of Year	Charged to Costs and Expenses	Other*	Deductions**	Balance at End of Year
			(In thousands)		
Allowance for doubtful accounts:					
2013	**$10,818**	**$5,725**	**$1,395**	**$ 7,853**	**$10,085**
2012	12,407	7,064	1,754	10,407	10,818
2011	15,284	3,977	2,112	8,966	12,407

* 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 March 4, 2013, filed as Exhibit 3 to Form 10-Q for the quarter ended March 31, 2013, filed on May 7, 2013, 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 May 16, 2013, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2013, filed on August 7, 2013, in File No. 1-3480*

+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 4, 2013, and Rules and Regulations, as amended March 4, 2013, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2013, filed on May 7, 2013, 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) 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(j) Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan as amended March 4, 2013, filed as Exhibit 10.2 to Form 8-K dated March 4, 2013, filed on March 7, 2013, in File No. 1-3480*

+10(k) 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(l) MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of January 3, 2014**

+10(m) 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(n) 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(o) 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(p) 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(q) 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(r) 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(s) 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(t) 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(u)	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(v)	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(w)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 19, 2012, filed as Exhibit 10(z) to Form 10-K for the year ended December 31, 2012, filed on February 28, 2013, in File No. 1-3480*
+10(x)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*
+10(y)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013, filed as Exhibit 10(c) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*
+10(z)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 23, 2013, filed as Exhibit 10(d) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*
+10(aa)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 31, 2013**
+10(ab)	Employment Letter for Jeffrey S. Thiede, dated May 16, 2013**
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(a)	Ryder Scott Company, L.P. report dated January 27, 2014**
99(b)	Equity Distribution Agreement entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC, filed as Exhibit 1 to Form 8-K dated May 20, 2013, filed on May 20, 2013, in File No. 1-3480*
99(c)	First Amendment to Equity Distribution Agreement, dated December 2, 2013, entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC**
101	The following materials from MDU Resources Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2013, 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 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 21, 2014

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 21, 2014
/s/ Doran N. Schwartz Doran N. Schwartz (Vice President and Chief Financial Officer)	Chief Financial Officer	February 21, 2014
/s/ Nathan W. Ring Nathan W. Ring (Vice President, Controller and Chief Accounting Officer)	Chief Accounting Officer	February 21, 2014
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 21, 2014
/s/ Thomas Everist Thomas Everist	Director	February 21, 2014
/s/ Karen B. Fagg Karen B. Fagg	Director	February 21, 2014
/s/ Mark A. Hellerstein Mark A. Hellerstein	Director	February 21, 2014
/s/ A. Bart Holaday A. Bart Holaday	Director	February 21, 2014
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 21, 2014
/s/ Thomas C. Knudson Thomas C. Knudson	Director	February 21, 2014
/s/ William E. McCracken William E. McCracken	Director	February 21, 2014
/s/ Patricia L. Moss Patricia L. Moss	Director	February 21, 2014
/s/ J. Kent Wells J. Kent Wells	Director	February 21, 2014
/s/ John K. Wilson John K. Wilson	Director	February 21, 2014

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MDU RESOURCES
GROUP, INC.

David L. Goodin
President and
Chief Executive Officer

1200 W. Century Ave.
Bismarck, ND 58503
Mailing address:
P.O. Box 5650
Bismarck, ND 58506-5650
(701) 530-1000
www.MDU.com

March 12, 2014

To Our Stockholders:

Please join us for the 2014 Annual Meeting of Stockholders. The meeting will be held on Tuesday, April 22, 2014, 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 2013 Annual Meeting at which 89.07 percent of the common stock was represented in person or by proxy. We hope for an even greater representation at the 2014 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, 2014, 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 22, 2014

Important Notice Regarding the Availability of Proxy Materials for the Stockholder Meeting to Be Held on April 22, 2014

The 2014 Notice of Annual Meeting and Proxy Statement and 2013 Annual Report to Stockholders are available at www.mdu.com/proxystatement.

March 12, 2014

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 22, 2014, at 11:00 a.m., Central Daylight Saving Time, for the following purposes:

(1) Election of eleven 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 registered public accounting firm for 2014;

(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, 2014, 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, 2014, 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 12, 2014, to solicit your proxy for use at our annual meeting of stockholders on April 22, 2014, 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 $7,500 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 2014, 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, 2014. 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, 2014, we had 189,789,192 shares of common stock outstanding entitled to one vote per share.

What am I voting on? You are voting on:

- election of eleven directors nominated by the board of directors for one-year terms
- ratification of the appointment of Deloitte & Touche LLP as the company's independent registered public accounting firm for 2014
- 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 Registered Public Accounting Firm for 2014

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 Thomas C. Knudson for his service on the board and the compensation committee. Mr. Knudson is not standing for re-election as a director after serving on the board since 2008.

All nominees for director are nominated to serve one-year terms until the annual meeting of stockholders in 2015 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 64

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 40 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 26 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 19 years of board experience as well as extensive knowledge of our business.

Karen B. Fagg

Age 60

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 June 2000, and chairman, chief executive officer, 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. In 2013, she served on a three-person selection committee appointed by the Attorney General to identify trustees for the Montana Healthcare Foundation Board. She also became a board member of the Montana Justice Foundation, whose mission is to achieve equal access to justice for all Montanans through effective funding and leadership, and of the First Interstate BancSystem Foundation, which has a strong commitment to community. She has been a board member of the Billings Chamber of Commerce since July 2009 and its board chair since July 2013, as well as a member of the Billings Catholic School Board since December 2011. 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. 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 through 2006, she served on the ZooMontana Board and as vice chair from 2005 through 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 also has 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 over 20 years of business leadership and management experience, including over 8 years 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 52

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.

PROXY

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 30 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 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 Terry D. Hildestad as our president and chief executive officer in January 2013 was in recognition of the board's belief that he has 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.

Mark A. Hellerstein

Age 61

Director Since 2013
Audit Committee

Mr. Hellerstein was chief executive officer of St. Mary Land & Exploration Company (now SM Energy Company), an energy company engaged in the acquisition, exploration, development, and production of crude oil, natural gas, and natural gas liquids, from 1995 until February 2007; he was president from 1992 until June 1996 and executive vice president and chief financial officer from 1991 until 1992. He was first elected to the board of St. Mary in 1992 and served as chairman of the board from 2002 until May 2009. Prior to joining St. Mary, from 1980 to 1991 Mr. Hellerstein's career included positions as chief financial officer of CoCa Mines Inc., which mined and extracted minerals from lands previously held by the public through the Bureau of Land Management; American Golf Corporation, which manages golf courses in the United States; and, Worldwide Energy Corporation, an oil and gas acquisition, exploration, development, and production company with operations in the United States and Canada. Mr. Hellerstein served on the board of directors of Transocean Inc., a leading provider of offshore drilling services for oil and gas wells, from December 2006 to November 2007.

Mr. Hellerstein's leadership has been recognized with induction into the Rocky Mountain Oil and Gas Hall of Fame, and Ernst & Young named Mr. Hellerstein both Rocky Mountain and National Entrepreneur of the Year in 2005 and 2006, respectively. He graduated number one in his class with a bachelor's degree in accounting from the University of Colorado. Mr. Hellerstein is a certified public accountant (CPA), on inactive status. He received the Elijah Watts Sells Gold Medal award for achieving the highest score in the United States on the November 1974 CPA exam out of 38,000 participants. Mr. Hellerstein has served on the board for Community Resources, Inc. since September 2013, which is a non-profit organization that brings programs into the Denver Public Schools to enhance education. He served as a board director on the Denver Children's Advocacy Center (Center) from August 2006 until December 2011, including as chairman the last three years, and continues to participate in and fund the Center's Safe from the Start Program. The Center's mission is to provide a continuum of care for traumatized children and their families.

The board concluded that Mr. Hellerstein 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. derives a significant portion of its earnings from oil and natural gas production, one of the company's growth centers. Mr. Hellerstein has extensive business experience, recognized excellence, and demonstrated success and leadership in this industry as a result of his 17 years of senior management experience and service as board chairman of St. Mary. His skills and experience enable him to contribute independent insight into the company's business and operations and the economic environment and long-term strategic issues the company faces. As a certified public accountant, on inactive status, with extensive financial experience as a result of his employment as chief financial officer with several companies, including public companies, Mr. Hellerstein contributes significant finance and accounting knowledge to our board and audit committee. His financial expertise assists the board in its oversight of the company's financial reporting and financial risk management functions. Mr. Hellerstein also brings to the board his knowledge of local, state, and regional issues involving the Rocky Mountain region where we have important operations.

A. Bart Holaday
Age 71

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 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; and is chairman and chief executive officer of the Dakota Foundation, a nonprofit foundation that fosters social entrepreneurship. He is a past member of the board of directors of the University of North Dakota Foundation, National Venture Capital Association, Walden University, and the U.S. Securities and Exchange Commission advisory committee on the regulation of capital markets, and is a past 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.

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.

Dennis W. Johnson
Age 64

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 fourteenth 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 39 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 32 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 ten 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.

William E. McCracken — Director Since 2013
Age 71 — Nominating and Governance Committee

Mr. McCracken served as chief executive officer of CA, Inc., one of the world's largest information technology management software companies, from January 2010 until January 7, 2013, after which he served as executive adviser to the new chief executive officer until March 31, 2013, and after that as a consultant to the company until December 31, 2013. Mr. McCracken was a director of CA, Inc. from May 2005 until January 7, 2013, serving as non-executive chairman of the board from June 2007 to September 2009, interim executive chairman from September 2009 to January 2010, and executive chairman from January 2010 to May 2010. He is president of Executive Consulting Group, LLC, a general business consulting firm, since 2002. During his 36-year career with International Business Machines Corporation, a manufacturer of information processing products and a technology, software, and networking systems manufacturer and developer, Mr. McCracken held a number of executive positions, including general manager of IBM printing systems division from 1998 to 2001, general manager of marketing, sales, and distribution for IBM PC Company from 1994 to 1998, and president of IBM's EMEA and Asia Pacific PC Company from 1993 to 1994. From 1995 to 2001, he served on IBM's Chairman's Worldwide Management Council, a group of the top 30 executives at IBM. Mr. McCracken was a director of IKON Office Solutions, Inc., a provider of document management systems and services, from 2003 to 2008, where he served on its audit committee, compensation committee, and strategy committee at various points in time during his tenure as a director.

Mr. McCracken has a bachelor of science degree in physics and mathematics from Shippensburg University. He has served on the board of the National Association of Corporate Directors (NACD), a non-profit membership organization for corporate board members, since 2010, and was named by the NACD as one of the top 100 most influential people in the boardroom in 2009. He served on that organization's 2009 blue ribbon commission on risk governance and in 2012 co-chaired its blue ribbon commission on board diversity. He was elected vice-chair and has been a board member of the Millstein Center for Global Markets and Corporate Ownership at Columbia University since 2013 and is the New York chairman of the chairman's forum since 2011. He is board chairman of Lutheran Social Ministries of New Jersey, a charitable organization that provides adoption, assisted living, counseling, and immigration and refugee services, and also is a board member of PENCIL, a nonprofit organization that partners businesses with public schools.

The board concluded that Mr. McCracken 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. McCracken has extensive executive leadership experience and significant experience in information technology through his tenure at CA, Inc. and IBM. This experience coupled with his service as the chair or a member of the board of other public companies and the NACD will enable him to provide insight into the operations, challenges, and complex issues our company is facing in today's environment and to make significant contributions to the board's oversight of operational risk management functions and corporate governance.

Patricia L. Moss
Age 60

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 improve access to capital and create private-public partnerships, 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.

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.

Harry J. Pearce
Age 71

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 and serves on the excellence, finance, and compensation committees 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 57

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 corporation 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 34 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 59

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 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 REGISTERED PUBLIC ACCOUNTING FIRM

The audit committee at its February 2014 meeting appointed Deloitte & Touche LLP as our independent registered public accounting firm for fiscal year 2014. The board of directors concurred with the audit committee's decision. Deloitte & Touche LLP has served as our independent registered public accounting firm since fiscal year 2002.

Although your ratification vote will not affect the appointment or retention of Deloitte & Touche LLP for 2014, the audit committee will consider your vote in determining its appointment of our independent registered public accounting firm for the next fiscal year. The audit committee, in appointing our independent registered public accounting firm, 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 registered public accounting firm for 2014.

Ratification of the appointment of Deloitte & Touche LLP as our independent registered public accounting firm for 2014 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 registered public accounting firm, Deloitte & Touche LLP, billed or is expected to bill us for professional services rendered for 2013 and 2012:

	2013	2012*
Audit Fees(a)(e)	$2,760,620	$2,510,138
Audit-Related Fees(b)	33,800	63,110
Tax Fees(c)(e)	66,049	23,745
All Other Fees(d)	1,374,455	0
Total Fees(f)	$4,234,924	$2,596,993
Ratio of Tax and All Other Fees to Audit and Audit-Related Fees	51.55%	0.92%

* The 2012 amounts were adjusted from amounts shown in the 2013 proxy statement to reflect actual amounts.

(a) Audit fees for 2013 and 2012 consist 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, comfort letter work relating to the offering of common stock (2013 only), and work related to responding to a comment letter from the Securities and Exchange Commission (2013 only).

(b) Audit-related fees for 2013 and 2012 are associated with accounting research assistance, technical accounting consultation regarding variable interest entities, guarantees, and financing agreements (2013 only), workpaper review requested by the Idaho Public Utilities Commission (2012 only), and the compliance audit for the U.S. Department of Energy (2012 only).

(c) Tax fees for 2013 relate to consulting services for federal income tax pollution control associated with the Big Stone power plant. Tax fees for 2012 relate to the review of permanent tax benefits associated with Medicare Part D subsidies.

(d) All other fees for 2013 relate to assistance in an internal investigation. There were no fees in this category for 2012.

(e) Audit fees for 2013 include $30,000 associated with a financial statement audit, and tax fees for 2013 include $50,000 associated with tax services, in each case for Dakota Prairie Refining, LLC. These fees are paid by Dakota Prairie Refining, LLC, but are included in this table because Dakota Prairie Refining, LLC, is considered a variable interest entity with respect to MDU Resources and consolidated in its financial statements.

(f) Total fees reported above include out-of-pocket expenses related to the services provided of $385,216 for 2013 and $353,627 for 2012.

Pre-Approval Policy

The audit committee pre-approved all services Deloitte & Touche LLP performed in 2013 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 2013 total target direct compensation in the form of incentive compensation, except in the case of one officer promotion where his incentive compensation was 47% of his total target direct 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, 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 2013. Accordingly, the following resolution is submitted for stockholder vote at the 2014 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.

Executive Summary

Named Executive Officers

Our named executive officers for 2013 were:

- David L. Goodin, who became president and chief executive officer of MDU Resources Group, Inc. on January 4, 2013; Mr. Goodin was not a named executive officer last year
- Terry D. Hildestad, our former president and chief executive officer, who retired on January 3, 2013
- Doran N. Schwartz, our vice president and chief financial officer
- J. Kent Wells, our vice chairman and the president and chief executive officer of our exploration and production business segment, Fidelity Exploration & Production Company, a direct wholly-owned subsidiary of WBI Holdings, Inc.
- Jeffrey S. Thiede, who became president and chief executive officer of our construction services business segment, MDU Construction Services Group, Inc., effective April 30, 2013; Mr. Thiede was not a named executive officer last year and
- Paul K. Sandness, our general counsel and secretary; Mr. Sandness was not a named executive officer last year.

Since Mr. Hildestad retired at the beginning of the year and received no increase in base salary or incentive compensation for 2013, we do not discuss Mr. Hildestad further in the Compensation Discussion and Analysis.

The chief executive officer of the construction services and construction materials and contracting business segments retired in April 2013. His responsibilities were divided between Jeffrey S. Thiede, who was promoted from president to president and chief executive officer of the construction services segment, and David C. Barney, who was promoted from president to president and chief executive officer of the construction materials and contracting segment and is not a named executive officer.

Key Financial Results for 2013

Consolidated GAAP earnings in 2013 were $278.2 million, or $1.47 cents per share, compared to a loss of $1.4 million, or 1 cent per share, in 2012.

Our total stockholder return for 2013 was 47.5%, as compared to 2.1% for 2012. Our average annual total stockholder return for the five-year period ended December 31, 2013 was 10.5%, compared to (2.3)% for the five-year period ended December 31, 2012.

In 2013 the company generated a 7.2% return on invested capital compared to a 6.7% weighted average cost of capital.

Total Realized Pay Compared to Total Compensation from the Summary Compensation Table

The compensation committee believes considering total realized pay, the actual remuneration received by the named executive, is equally as important as considering total compensation as presented in the Summary Compensation Table. Total realized pay reflects the compensation actually earned, which can differ substantially from 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. In addition, the Summary Compensation Table may show an increase in change in pension value and above-market earnings on nonqualified deferred compensation, depending on the valuation assumptions and discount rates used to calculate present value of pension benefits. The company excludes change in pension value and above-market earnings on nonqualified deferred compensation from total realized pay because:

- increase in change in pension value can have a large impact on total compensation as reported in the Summary Compensation Table
- for some of our named executive officers for 2013, the change in pension value was negative due to the use of a higher discount rate to calculate present value; however, unlike when the value is positive, the negative value does not reduce total compensation as reported in the Summary Compensation Table and

- the change in pension value is the difference in the present value of our qualified defined benefit retirement plan and our Supplemental Income Security Plan benefits, and the Supplemental Income Security Plan benefits partially depend on continued future employment in the case of Messrs. Goodin and Schwartz.

We define total realized pay as the sum of:

- base salary
- annual incentive award paid with respect to the year
- the value realized upon the vesting of long-term incentive awards of performance shares during the year and
- all other compensation as reported in the Summary Compensation Table.

The following table compares total realized pay for our named executives in 2013 to the total compensation as presented in the Summary Compensation Table. This table is not intended to be a substitute for the Summary Compensation Table.

Named Executive Officer	Base Salary ($)	Annual Incentive Awards Paid ($)	Value Realized upon Vesting of Performance Shares ($) (1)	All Other Compensation ($)	Total Realized Pay ($)	Total Compensation from the Summary Compensation Table ($)
David L. Goodin	625,000	1,610,625	0	37,517	2,273,142	4,047,413
Doran N. Schwartz	345,000	296,355	0	34,881	676,236	1,047,274
J. Kent Wells	570,000	1,425,000	N/A	20,556	2,015,556	3,524,975
Jeffrey S. Thiede	367,068	825,000	N/A	66,282	1,258,350	1,258,350
Paul K. Sandness	344,000	354,595	0	39,131	737,726	1,124,864

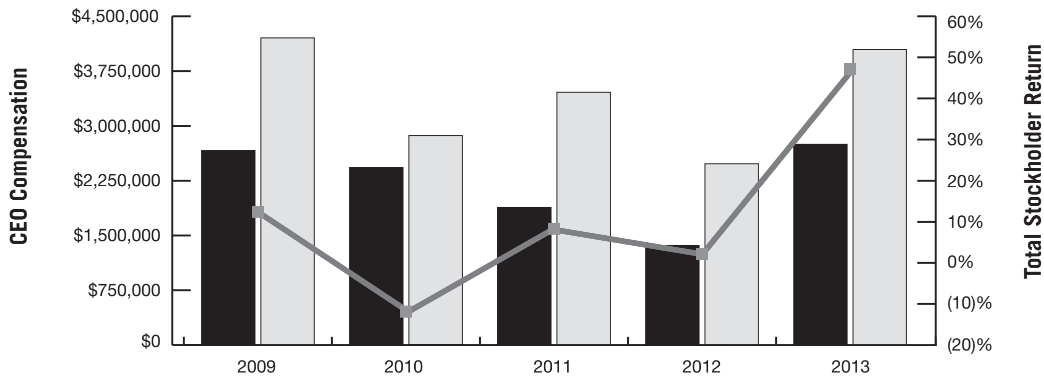
(1) Performance shares and dividend equivalents granted for the 2010-2012 performance period did not vest and were forfeited because performance was below threshold.

With respect to our chief executive officer, the following table demonstrates our pay for performance approach by comparing:

- 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 2009 and 2010 (none vested during 2011, 2012, or 2013)
- total compensation as reported in the Summary Compensation Table and
- one-year total stockholder returns for 2009 through 2013.

For years 2009 through 2012, the compensation information is for Mr. Hildestad, our chief executive officer for those years, and for 2013, the compensation information is for Mr. Goodin. This table is not intended to be a substitute for the Summary Compensation Table.

5 Year CEO Compensation and Total Stockholder Return



	2009	2010	2011	2012	2013
Total Realized Pay	$2,657,250	$2,344,221	$1,742,249	$1,306,474	$2,273,142
Total Compensation from Summary Compensation Table	$4,203,004	$2,860,918	$3,566,327	$2,558,778	$4,047,413
1 Year Total Stockholder Return	12.9%	(11.3)%	9.1%	2.1%	47.5%

The compensation committee believes its approach to structuring the chief executive officers' compensation is effective; as displayed in the above chart, 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.

Process for Determination of 2013 Compensation

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.

Role of Compensation Consultants

For 2013, 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.

Our executive compensation policy provides 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. For 2013 compensation, the compensation committee retained Towers Watson, a nationally recognized consulting firm, to perform this assessment and to assist the compensation committee in establishing competitive compensation targets for 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, 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 and
- verify the competitiveness of target short-term and long-term incentives 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 target incentives based on the competitive data and
- address general trends in chief executive officer compensation.

The compensation surveys and databases used by Towers Watson were:

Survey*	Number of Companies Participating (#)	Median Number of Employees (#)	Number of Publicly-Traded Companies (#)	Median Revenue (000s) ($)
Towers Watson 2011 CDB General Industry Executive Database	411	18,300	345	5,823,000
Towers Watson 2011 CDB Energy Services Executive Database	108	2,800	75	2,490,000
Mercer 2011 Total Compensation Survey for the Energy Sector	290	Not Reported	233	928,000
Towers Watson 2011 CSR Report on Top Management Compensation	1,574	4,800	630	1,513,000

* 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 2011, 2012, and 2013 were approximately $4.0, $4.1, and $4.5, respectively. Towers Watson aged the data from the date of the surveys by 3% on an annualized basis to estimate 2013 competitive targets.

After its February 2013 meeting, the compensation committee authorized the company to engage Towers Watson to provide competitive practice information with respect to the treatment by other exploration and production companies of ceiling test impairments for annual incentive purposes. Towers Watson analyzed the following fifteen companies with an earnings-based measure impacted by impairment charges:

- Anadarko Petroleum Corporation
- Apache Corporation
- Atmos Energy Corporation
- Black Hills Corporation
- Chesapeake Energy Corporation
- Eagle Rock Energy Partners, L.P.
- Encana Corporation
- Goodrich Petroleum Corporation
- Niska Gas Storage Partners LLC
- PDC Energy, Inc.
- PVR Partners L.P.
- Quicksilver Resources Inc.
- SM Energy Company
- Ultra Petroleum Corp.
- WPX Energy, Inc.

Role of Management

The chief executive officers during 2012 and 2013 played an important role in recommending 2013 compensation to the committee for the other named executive officers. Mr. Hildestad recommended 2013 compensation for Messrs. Schwartz, Wells, and Sandness after assessing their performance during 2012. Mr. Hildestad did not make any recommendations with respect to Mr. Goodin's compensation for 2013. In connection with Mr. Thiede's promotion, Mr. Goodin recommended his compensation for the remainder of 2013. The chief executive officers considered the relative value of the named executive officers' positions and their salary grade classifications. They reviewed the competitive assessment prepared by Towers Watson to formulate 2013 compensation recommendations for the compensation committee. The chief executive officers attended compensation committee meetings, but were not present during discussions regarding their own compensation.

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:

- leadership
- leading with integrity
- achievement focus
- risk management
- mentoring
- financial responsibility
- safety

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.

Timing of Compensation Decisions for 2013

The compensation committee, in conjunction with the board of directors, determined all compensation for each named executive officer for 2013. 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 2013 salary grades at its August 2012 and November 2012 meetings. At the November 2012 meeting, it established individual base salaries, target annual incentive award levels, and target long-term incentive award levels for 2013, except for Mr. Thiede, whose base salary and target annual incentive award were approved at the May 2013 meeting. At the February and March 2013 meetings, the compensation committee and the board of directors determined 2013 annual and long-term incentive awards, along with payments based on performance for the 2012 annual incentive awards and no payments for the 2010-2012 performance share awards. The February and March meetings occurred after the release of earnings for the prior year.

Stockholder Advisory Vote ("Say on Pay")

Our stockholders had their third advisory vote on our named executive officers' compensation at the 2013 Annual Meeting of Stockholders. Approximately 96% of the shares present in person or represented by proxy and entitled to vote on the matter approved the named executive officers' compensation. The 96% approval is slightly higher than the results of our say on pay vote at the 2012 Annual Meeting, which was 92%. The compensation committee and the board of directors considered the results of the votes at their November 2012, May 2013, and November 2013 meetings and did not change our executive compensation program as a result of the votes.

Salary Grades for 2013

The compensation committee determines the named executive officers' base salaries and target annual and long-term incentives 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 target annual and long-term incentive 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.

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.

The committee increased the base salary midpoints for 2013 in salary grades A through I by a total of 2.8%, since the midpoints had not been increased in three years and the competitive assessment indicated that target total annual compensation and total direct compensation were below the market median at the 50th percentile. The midpoint of salary grade I, which is Messrs. Schwartz's and Sandness' salary grade, was increased by 3.1% from $325,000 to $335,000.

The committee established a new salary grade L for 2013 for our president and chief executive officer position, which was formerly in salary grade K. Based on the competitive assessment, the committee established the midpoint of salary grade L at $763,000.

The committee assigned the vice chairman and president and chief executive officer of Fidelity Exploration & Production Company to salary grade K in recognition of the greater responsibility that Mr. Wells would assume as vice chairman. The midpoint of salary grade K was established at $500,000 to accommodate the higher market compensation data associated with his responsibilities.

In connection with his promotion, Mr. Thiede was moved from salary grade H to salary grade J, with a midpoint of $390,000, which has been the midpoint for that salary grade for a number of years.

The committee did not change the target incentive compensation guidelines for the salary grades, except that Mr. Sandness' target annual and long-term incentives were increased to 60% and 85% of base salary, respectively, to place his target total annual compensation and total direct compensation closer to the market median.

Our named executive officers' salary grade classifications for 2013 are listed below, along with the base salary ranges associated with each classification:

			2013 Salary Grade Base Salary (000s)		
Position	Grade	Name	Minimum ($)	Midpoint ($)	Maximum ($)
President and CEO	L	David L. Goodin	610	763	916
Vice President and CFO	I	Doran N. Schwartz	268	335	402
Vice Chairman and President and CEO, Fidelity Exploration & Production Company	K	J. Kent Wells	400	500	600
President and CEO, Construction Services Group	J	Jeffrey S. Thiede	312	390	468
General Counsel and Secretary	I	Paul K. Sandness	268	335	402

Allocation of Total Target Compensation for 2013

Incentive compensation, which consists of annual cash incentive awards and three-year performance share awards under our Long-Term Performance-Based Incentive Plan, comprises a significant portion of our named executive officers' total target compensation 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 significant portion of their target compensation contingent upon results that are beneficial to stockholders.

The following table shows the allocation of total target compensation for 2013 among the individual components of base salary, annual incentive, and long-term incentive:

		% of Total Target Compensation Allocated to Incentives		
Name	% of Total Target Compensation Allocated to Base Salary (%)	Annual (%)	Long-Term (%)	Annual + Long-Term (%)
David L. Goodin	25.0	37.5	37.5	75.0
Doran N. Schwartz	44.4	22.2	33.4	55.6
J. Kent Wells	23.5	29.4	47.1	76.5
Jeffrey S. Thiede (1)	52.6	47.4	–	47.4
Paul K. Sandness	40.8	24.5	34.7	59.2

(1) Mr. Thiede's percentages were calculated using a base salary that was prorated for 2013 as follows: one-third at an annualized rate of $330,000 and two-thirds at an annualized rate of $385,000. Mr. Thiede was not a participant in the Long-Term Performance-Based Incentive Plan in 2013.

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. As discussed later, Mr. Goodin's long-term incentive percentage was kept at a lower level to balance his higher Supplemental Income Security Plan benefit. 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, discussed later, 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.

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 2008 through 2012 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 2008 through 2012, our average annual stockholder return was (2.3)%. Therefore, our pay ratio was 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 2008 through 2012 period.

2013 Compensation for Our Named Executive Officers

Base Salaries, Total Annual Compensation, and Total Direct Compensation

David L. Goodin

In connection with Mr. Goodin's promotion to president and chief executive officer of the company effective January 4, 2013, the compensation committee moved Mr. Goodin from salary grade J to salary grade L, with a midpoint of $763,000, and recommended a base salary increase for Mr. Goodin from $385,000 to $625,000. The committee noted that the $625,000 was below the median salary of $650,000 for the chief executive officers from the performance graph peer companies and below the median salary of $930,000 for the chief executive officers from the salary survey data, both as noted in the competitive assessment. The committee believed it was appropriate for Mr. Goodin's 2013 base salary to be less than market and less than the 2013 midpoint due to his newness in the position. The committee also established Mr. Goodin's target total annual cash compensation of $1,562,500, which was above the median total cash compensation of $1,335,000 paid to chief executive officers from the performance graph peer companies and below the median total cash compensation of $1,920,000 paid to chief executive officers from the salary survey data, both as noted in the competitive assessment. From a total direct compensation perspective, the committee established a target of $2,500,000, which was below the competitive reference points of $2,970,000 for the performance graph peer group and $4,685,000 for the salary survey companies.

Doran N. Schwartz

For 2013, the compensation committee awarded Mr. Schwartz, our vice president and chief financial officer, a 15.0% increase, raising his salary from $300,000 to $345,000, or to 103% of the midpoint of salary grade I. Combined with his target annual and long-term incentive, this would result in target total annual compensation of 64% and total direct compensation of 57% of the 2013 competitive salary survey data at the 50th percentile. The compensation committee's rationale for the increase was in recognition of his:

- renewal and expansion of the company's credit facility
- continued growth in the treasury area
- cultivation of excellent relationships with the investment community and
- relatively low salary compared to the chief financial officers of performance graph peer companies.

J. Kent Wells

For 2013, the compensation committee awarded Mr. Wells, our vice chairman and president and chief executive officer of Fidelity Exploration & Production Company, a 3.6% increase, raising his salary from $550,000 to $570,000, or 114% of the midpoint of salary grade K. Combined with his target annual and long-term incentives, this would result in target total annual compensation of 118% and total direct compensation of 95% of the 2013 competitive salary survey data at the 50th percentile. The compensation committee's rationale for the increase was in recognition of:

- a 25% increase in production from 2011 to 2012
- a shift in the production mix from 80% natural gas and 20% oil and liquids in 2011 to 60% natural gas and 40% oil and liquids in 2012 and
- outstanding leadership at Fidelity Exploration & Production Company.

Jeffrey S. Thiede

Mr. Thiede was promoted to president and chief executive officer of MDU Construction Services Group, Inc. effective April 30, 2013. In connection with his promotion, the compensation committee moved Mr. Thiede from salary grade H to salary grade J with a midpoint of $390,000 and increased Mr. Thiede's base salary from $330,000 to $385,000. Combined with his target annual incentive, his prorated target total annual compensation was $696,667. The committee's rationale for the increase was recognizing Mr. Thiede's assumption of the additional duties and responsibilities as chief executive officer, as well as recognizing the success he achieved as president of MDU Construction Services Group, Inc. since January 2012.

Paul K. Sandness

For 2013, the compensation committee awarded Mr. Sandness, our general counsel and secretary, a 3% increase, raising his salary from $334,000 to $344,000, or to 103% of the midpoint of salary grade I. Combined with his increased target annual and long-term incentives, this would result in target total annual compensation of 89% and total direct compensation of 86% of the 2013 competitive salary survey data at the 50th percentile. The compensation committee's rationale for the increase was in recognition of Mr. Sandness' successful management of company litigation and his leadership in the corporate governance area.

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.

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, because:

- earnings per share is a generally accepted accounting principle measurement and is a key driver of stockholder return over the long-term and
- return on invested capital measures how efficiently and effectively management deploys capital, where sustained returns on invested capital in excess of a business segment's cost of capital create value for our stockholders.

For the first time in 2013, the compensation committee selected earnings as the performance measure for two business segments. For the construction services segment, key earnings levels were selected in order to balance conservative financial planning as well as earnings volatility, instead of tying performance to allocated earnings per share and budgeted return on invested capital.

To provide the compensation committee with a competitive practice reference point in terms of how other exploration and production companies treat ceiling test impairments for annual incentive purposes, we engaged Towers Watson to prepare the analysis discussed in the Role of Compensation Consultants section above. The committee considered Towers Watson's report and selected earnings, as adjusted, for the exploration and production segment to motivate the chief executive officer to increase and maintain production at a high level and develop the appropriate mix of production and replacement reserves, without regard to the effect on earnings of non-cash impairments and hedge accounting, the pricing components over which he had no control.

For the named executive officers working at MDU Resources Group, Inc., who were Messrs. Goodin, Schwartz, and Sandness, the compensation committee continued to base annual incentives on the achievement of performance goals at the business segments: (i) the construction materials and contracting and construction services segments, taken together, (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.

As established by the compensation committee in March 2013, the annual performance measures and goal weightings for the business segment leaders were:

		Business Segment Goal Weighting			Company Goal Weighting
Position	Business Segment	Budgeted Allocated EPS (%)	Budgeted ROIC (%)	Budgeted Earnings (%)	EPS (%) (1)
Chief Executive Officer	Construction Materials & Contracting	18.75	18.75	–	25.0
	Construction Services	–	–	37.5(2)	
President and Chief Executive Officer	Pipeline and Energy Services	37.5	37.5	–	25.0
President and Chief Executive Officer	Electric and Natural Gas Distribution	37.5	37.5	–	25.0
President and Chief Executive Officer	Exploration and Production	–	–	75.0(3)	25.0

(1) Earnings per share for purposes of the annual incentive calculation reflect the adjustments referred to in footnote 3.

(2) Earnings were defined as GAAP earnings.

(3) Earnings were defined as GAAP earnings reported for the exploration and production segment, adjusted to exclude the (i) effect on earnings of any noncash write-downs of oil and natural gas properties due to ceiling test impairment charges and any associated earnings benefit resulting from lower depletion, depreciation and amortization expenses and (ii) the effect on earnings of any noncash gains and losses that result from (x) ineffectiveness in hedge accounting, (y) derivatives that no longer qualify for hedge accounting treatment, or (z) the discontinuation of hedge accounting treatment.

After the chief executive officer of our two construction segments retired in late April 2013 and Messrs. Thiede and Barney were promoted, the compensation committee left Mr. Thiede's annual incentive performance measure unchanged from what it had been earlier in the year, namely the construction services business segment's GAAP earnings. This determination had no effect on the calculation of the annual incentive awards for the executive officers at MDU Resources Group, Inc., as discussed above, which were to be calculated as if the former chief executive officer of the construction business segments had remained employed through the end of 2013.

Except for our construction services business segment, 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. 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. If the compensation committee utilizes a return on invested capital target for a business segment, it 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.

In the case of our construction services business segment, we utilized key earnings levels to structure the annual incentive. The specific earnings levels and their associated incentive payment amounts are addressed in Construction Services Segment Earnings Goal section below.

Our Named Executive Officers' Target Annual Incentive Compensation

The compensation committee established the named executive officers' target annual incentive as a percentage of each officer's actual 2013 base salary.

Messrs. Goodin's, Schwartz's, and Sandness' 2013 target annual incentives were 150%, 50%, and 60% of base salary, respectively, based on the following:

- In connection with his promotion, Mr. Goodin's target annual incentive was set at 150% of base salary, or $937,500, which was above the 107% and 103% of base salary paid to chief executive officer positions based on salary survey data and performance graph peer group data, respectively, from the competitive assessment. The committee's rationale for assigning an above-market target annual incentive percentage was to offset a below-market target long-term incentive and to ensure, from an internal equity standpoint, that Mr. Goodin's target incentive was above the target incentives of his direct reports.

- For Mr. Schwartz, the target annual incentive of 50% of base salary was below the 71% and 58% of base salary paid to chief financial officers based on salary survey data and performance graph peer group data, respectively, from the competitive assessment. Since prior years had shown little difference between Mr. Schwartz's target incentive and the targets from the competitive assessments, the committee decided to forego changing his target.
- For Mr. Sandness, the target annual incentive was increased from 50% to 60% of base salary to be approximately equal to the 59% of base salary paid to top legal executives based on salary survey data from the competitive assessment.

Mr. Wells' 2013 target incentive was unchanged at 125% of base salary, which was above the 57% of base salary paid to comparable positions in the survey data and below the average of 234% of base salary paid at exploration and production companies (Berry Petroleum Company, EQT Corporation, and Whiting Petroleum Corporation) in our performance graph peer group from the competitive assessment. The compensation committee determined, as it had last year, that the target incentive of 125% of base salary was appropriate given the significant investment in the exploration and production segment and the desire to incentivize and motivate Mr. Wells to generate earnings that can greatly impact overall company earnings.

Mr. Thiede's 2013 target incentive was 90% of base salary, which remained unchanged from the target incentive he had before his promotion, but was to be calculated based on his prorated base salary. His position was not included in the competitive assessment prepared by Towers Watson. The committee believed maintaining the 2013 target incentive of 90% of base salary was appropriate because it would compensate Mr. Thiede for not having received any long-term performance share grants.

MDU Resources Group, Inc. EPS Goal

The MDU Resources Group, Inc. earnings per share component represented 25% of the award opportunity for all business segment leaders except for Mr. Thiede. Payout could range from no payment if the results were below 85% of the $1.27 target to a 200% payout if the results were $1.46 or higher. The committee set the target at $1.27, which was above the 2012 target of $1.19 and above the adjusted 2012 results of $1.15, which eliminated the effect of $246.8 million after-tax noncash charges relating to the write-down of oil and natural gas properties in 2012, discontinued operations, and the net benefit related to natural gas gathering operations litigation. The 2013 target was established based on adjusted earnings at the exploration and production segment as described in footnote 3 to the table under What the Performance Measures Are and Why We Chose Them above. The higher 2013 earnings per share target level was based primarily on anticipated higher earnings at all business segments.

Earnings per share for 2013 were, on a GAAP basis, $1.47 and, on an adjusted basis, $1.49. The payment on this component was 200% of target.

Exploration and Production Segment Earnings Goal

For the exploration and production segment, 75% of the 2013 award opportunity was based on earnings adjusted as described in footnote 3 to the table under What the Performance Measures Are and Why We Chose Them above. Payout could range from no payment if 2013 earnings were below the 90% level to a 200% payout if the segment's 2013 earnings were at or above the 105% level.

The committee set the exploration and production segment's 2013 earnings target level at $84 million, which was above the 2012 target level of $78.4 million and 20.7% above 2012 adjusted results, which excluded the noncash ceiling test impairments. The higher 2013 earnings target level was approved by the board in the 2013 business plan and also based on an anticipated increase in production and continued shifting of production to more oil and natural gas liquids and less natural gas.

The segment's 2013 earnings were $98.4 million equating to a 200% payment on the segment earning's component, which coupled with MDU Resources Group, Inc.'s earnings per share being 200% of target, resulted in a 2013 annual incentive payment for Mr. Wells of $1,425,000 or 200% of target.

Electric and Natural Gas Distribution Segments EPS and ROIC Goals

For the electric and natural gas distribution segments, 75% of the 2013 award opportunity was based on allocated earnings per share and budgeted return on invested capital, equally weighted. 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 2013 allocated earnings per share for the segment were at or above the 115% level and
- the 2013 return on invested capital was at or above the 115% level.

The committee set the 2013 target for allocated earnings per share higher than the 2012 target and higher than 2012 actual results to reflect anticipated growth in the western North Dakota region of the service territory. The committee set the 2013 return on invested capital target lower than the 2012 target level and higher than the 2012 actual results to reflect higher invested capital associated with its growth projects.

For 2013, the electric and natural gas distribution segments' earnings per share and return on invested capital were 108.3% and 103.4% of their respective targets, equating to 155.5% and 122.6%, respectively, of the target amount attributable to those components, which coupled with MDU Resources Group, Inc.'s earnings per share being 200% of target, led to overall results for these segments of 154.3% of the 2013 target annual incentive award.

Pipeline and Energy Services Segment EPS, ROIC, and Safety Goals
For the pipeline and energy services segment, 75% of the 2013 award opportunity was based on allocated earnings per share and budgeted return on invested capital, equally weighted. Payout could range from no payment if the results were below the 85% level to a 200% payout if:

- the 2013 allocated earnings per share for the segment were at or above the 115% level and
- the 2013 return on invested capital was at or above the 115% level.

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, which will be achieved only if 85% or more of the reports are submitted by the end of the next business day
- achieve the targeted vehicle accident incident rate of 1.85 or less and
- achieve the targeted personal injury incident rate of 2.3 or less.

The committee set the pipeline and energy services segment's 2013 allocated earnings per share target higher than the 2012 target, reflecting increased earnings associated with a full year's results of our natural gas processing facility. The 2013 allocated earnings per share target was set below the 2012 actual results due to the positive 2012 earnings impact of a benefit related to natural gas gathering operations litigation. The committee set the 2013 return on invested capital target below the 2012 target level and below the 2012 actual results, reflecting increased invested capital in our diesel refinery and reflecting the positive 2012 earnings impact of a benefit related to natural gas gathering operations litigation.

Results at the pipeline and energy services segment (before adjustment for the five safety goals) were 44.0% and 57.4%, respectively, of the 2013 allocated earnings per share and return on invested capital measures, resulting in no payment on either component. These results, coupled with MDU Resources Group, Inc.'s earnings per share being 200% of target and all five safety goals being met, led to overall results for these segments of 50% of the 2013 target annual incentive.

Construction Services Segment Earnings Goal
Mr. Thiede's 2013 incentive award opportunity was established by Mr. Goodin and the former chief executive officer of the construction services segment and was left unchanged by the compensation committee when he was promoted. His award opportunity was based solely on the construction services business segment's 2013 earnings, where the payout could range from no payment if the results were below $14.5 million to 250% of the target amount if the results were at or above $35.8 million.

For the construction services segment, key earnings levels were selected to balance conservative financial planning as well as earnings volatility, instead of tying performance to allocated earnings per share and budgeted return on invested capital. The committee set the business segment's 2013 earnings target at the level required to deliver a return on invested capital that was approximately equal to the business segment's weighted average cost of capital. The committee set the earnings required to generate a maximum payment at the level necessary to generate a return on invested capital of approximately 550 basis points above the business segment's weighted average cost of capital.

The construction services segment's 2013 earnings were $52.2 million.

Mr. Thiede's 2013 annual incentive payment was $825,000 or 250% of target.

Construction Services and Construction Materials and Contracting Segments Performance Goals

For purposes of determining the annual incentive awards of the MDU Resources Group, Inc. executives, including Messrs. Goodin, Schwartz, and Sandness, these segments were combined, with the targets and weightings structured as follows:

Construction Materials & Contracting's 2013 ROIC results as a % of 2013 target (weighted 18.75%)	Corresponding payment of annual incentive target based on ROIC	Construction Materials & Contracting's 2013 EPS results as a % of 2013 target (weighted 18.75%)	Corresponding payment of annual incentive target based on EPS	Construction Services' 2013 earnings(1) results as a % of 2013 target (weighted 37.5%)	Corresponding payment of annual incentive target based on earnings
Less than 85%	0%	Less than 85%	0%	Less than $14.5M	0%
100%	100%	100%	100%	100%	100%
191%	200%	115%	200%	$35.8M or greater	250%

(1) Earnings is defined as GAAP earnings reported for the construction services segment.

Targets and corresponding payments that fall in between stated levels are set out in more detail in the Narrative Discussion Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table.

For the construction materials and contracting business segment, the committee set the 2013 allocated earnings per share higher than the 2012 target and higher than 2012 actual result to reflect increased construction activity in western North Dakota, improvement in the Texas operations, and increased asphalt demand. The committee set the 2013 return on invested capital target higher than the 2012 target level and higher than the 2012 actual result due to higher anticipated earnings and continued restraint in the growth of the business segment's invested capital.

The construction services segment's 2013 earnings were $52.2 million, which was greater than 171% of the earnings target and equated to 250% of the annual incentive target. The construction materials and contracting segment's 2013 earnings per share and return on invested capital were 148.1% and 141.9% of their respective 2013 targets, equating to 173.3% of the target incentive amount attributable to those components.

Coupled with MDU Resources Group, Inc.'s earnings per share being 200% of target, overall results for 2013 were 208.8% of the 2013 target annual incentive award.

The following two tables show the 2012 and 2013 incentive plan performance targets and results by business segment.

	2012 Incentive Plan Performance Targets			2012 Incentive Plan Results		
Name	EPS Business Segment ($)	ROIC (%)	EPS MDU Resources ($)	EPS Business Segment ($)	ROIC (%)	EPS MDU Resources ($)
Pipeline and Energy Services	0.99	5.8	1.19	1.78	8.3	(.01)
Exploration and Production	2.10	6.9	1.19	(4.81)	(13.9)	(.01)
Construction Services	3.61	7.4	1.19	8.18	15.2	(.01)
Construction Materials and Contracting	0.31	3.5	1.19	0.49	4.1	(.01)
Electric and Natural Gas Distribution	1.16	6.2	1.19	1.08	5.8	(.01)

	2013 Incentive Plan Performance Targets				2013 Incentive Plan Results			
Name	EPS Business Segment ($)	ROIC (%)	Business Segment Earnings ($)	EPS MDU Resources ($)	EPS Business Segment ($) / (% of Target)	ROIC (%) / (% of Target)	Business Segment Earnings ($) / (% of Target)	EPS MDU Resources ($) / (% of Target)
Pipeline and Energy Services	1.16	5.4	–	1.27	0.51 / 0	3.1 / 0	–	1.49 / 200
Exploration and Production	–	–	84.0	1.27	–	–	98.4 / 200	1.49 / 200
Construction Services	–	–	20.9	–	–	–	52.2 / 250	–
Construction Materials and Contracting	0.52	4.3	–	1.27	0.77 / 200	6.1 / 146.5	–	1.49 / 200
Electric and Natural Gas Distribution	1.20	5.9	–	1.27	1.30 / 155.5	6.1 / 122.6	–	1.49 / 200

PROXY

The table below lists each named executive officer's 2013 base salary, target annual incentive percentage, and the annual incentive earned.

Name	2013 Base Salary (000s) ($)	2013 Target Annual Incentive (%)	2013 Annual Incentive Earned (% of Target)	2013 Annual Incentive Earned (000s) ($)
David L. Goodin	625.0	150.0	171.8	1,610.6
Doran N. Schwartz	345.0	50.0	171.8	296.4
J. Kent Wells	570.0	125.0	200.0	1,425.0
Jeffrey S. Thiede *	366.7	90.0	250.0	825.0
Paul K. Sandness	344.0	60.0	171.8	354.6

* Mr. Thiede's 2013 Annual Incentive Earned was established using a base salary that was prorated for 2013 as follows: one-third at an annualized rate of $330,000 and two-thirds at an annualized rate of $385,000.

Messrs. Goodin's, Schwartz's, and Sandness' 2013 annual incentives were paid at 171.8% 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	208.8%	28.5%	59.5%
Exploration and Production Segment	200.0%	26.6%	53.2%
Pipeline and Energy Services Segment	50.0%	9.8%	4.9%
Electric and Natural Gas Distribution Segments	154.3%	35.1%	54.2%
Total (Payout Percentage)			171.8%

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 2013, 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 4.58%. 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.

2013 Long-Term Incentives

Performance Share Awards

We use the Long-Term Performance-Based Incentive Plan, which has been approved by our stockholders, for long-term incentive compensation, with 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 has used relative stockholder return in comparison to the performance graph peer group as the performance measure for a number of years, including the 2013 performance share awards. The performance graph peer group consisted of the following companies when the committee granted performance shares in March 2013:

- 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
- Southwest Gas Corporation
- Sterling Construction Company
- SM Energy Company
- Swift Energy Company
- Texas Industries
- Vectren Corporation
- Vulcan Materials Company
- Whiting Petroleum Corporation

Since the March 2013 grant, Berry Petroleum Company has been removed from the performance graph peer group because it was acquired.

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 target annual incentive, we determined the target long-term incentive 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. The committee kept the chief executive officer's target long-term incentive below a level indicated from the competitive assessment. Mr. Goodin's target was 150% of base salary, below the salary survey median of 309% of base salary and below the performance graph peer group median of 247% of base salary for chief executive officers. The compensation committee has historically set the president and chief executive officer'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.

Messrs. Schwartz's and Wells' target long-term incentives were unchanged from 2012. Mr. Schwartz's target long-term incentive of 75% of base salary was below the salary survey median of 119% of base salary and below the performance graph peer group median of 143% of base salary for chief financial officers. Mr. Wells' target long-term incentive was 200% of base salary, which was above the salary survey median of 113% and below the performance graph peer group median of 444% of base salary paid to comparable positions based on survey data and proxy data, respectively, from the competitive assessment. We believe that Mr. Wells' long-term incentive target enhances retention since he cannot participate in any of our defined benefit retirement plans.

Mr. Thiede received no long-term incentive awards in 2013.

Mr. Sandness' target long-term incentive was increased from 75% to 85% of base salary and was slightly below the salary survey median of 92% of base salary.

On March 4, 2013, the board of directors, upon recommendation of the compensation committee, made performance share grants to the named executive officers, except Mr. Thiede. The compensation committee determined the target number of performance shares granted to each named executive officer by multiplying the named executive officer's 2013 base salary by his target long-term incentive and then dividing this product by the average of the closing prices of our stock from January 1, 2013 through January 22, 2013, as shown in the following table:

Name	2013 Base Salary to Determine Target ($)	2013 Target Long-Term Incentive at Time of Grant (%)	2013 Target Long-Term Incentive at Time of Grant ($)	Average Closing Price of Our Stock From January 1 Through January 22 ($)	Resulting Number of Performance Shares Granted on March 4 (#)
David L. Goodin	625,000	150	937,500	21.91	42,788
Doran N. Schwartz	345,000	75	258,750	21.91	11,809
J. Kent Wells	570,000	200	1,140,000	21.91	52,031
Jeffrey S. Thiede	–	–	–	–	–
Paul K. Sandness	344,000	85	292,400	21.91	13,345

Assuming our three-year (2013 to 2015) total stockholder return is positive, from 0% to 200% of the target grant will be paid out in February 2016 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.

During 2012, the compensation committee reviewed its long-term incentive award program and the use of performance shares as the only long-term award and relative total stockholder return as the sole performance measure. After considering alternative approaches, the committee determined to continue using performance shares as the only long-term award in order to keep long-term incentives based solely on performance. However, the committee modified the program due to:

- the added difficulty of comparing the company's diversified operations to a peer group comprised primarily of single industry firms and
- a number of the performance graph peer group companies also grant awards based solely on time vesting.

The committee determined, in order to be competitive and keep executives incentivized, to lower the threshold performance level from the 40th percentile to the 25th percentile and increase the threshold payout percentage from 10% to 20%. In addition, the performance level for maximum payout was lowered from the 90th percentile to the 75th percentile, as follows:

Long-Term Incentive Payout Percentages

The Company's Percentile Rank	Payout Percentage of March 4, 2013 Grant
75th or higher	200%
50th	100%
25th	20%
Less than 25th	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 2016 at the same time as the performance share awards are paid.

As had been established for awards granted beginning in 2011, 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:

Total Stockholder Return	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 2013 for 2010 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 March 5, 2010 for the 2010 through 2012 performance period. Our total stockholder return for the 2010 through 2012 performance period was (1.22)%, which corresponded to a percentile rank of 13% against our performance graph peer group and resulted in no shares or dividend equivalents being paid to the named executive officers.

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.

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 Mr. Goodin and Mr. Sandness, 10.5% for Mr. Schwartz, and 5% for Mr. Wells and Mr. Thiede.

Supplemental Income Security Plan

Benefits Offered

We offer certain key managers and executives, including all of our named executive officers, except Mr. Wells and Mr. Thiede, 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 effective 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 recommended, and the compensation committee approved, a 2013 SISP benefit level increase for Mr. Schwartz. The benefit level increase corresponded to one level below which Mr. Schwartz's 2013 salary would otherwise qualify. The recommendation was to recognize Mr. Schwartz's performance relating to the successful renewal of the company's credit facility.

The committee also approved a 2013 SISP benefit level increase for Mr. Goodin. The benefit level increase corresponded to one level below which Mr. Goodin's 2013 salary would otherwise qualify. The benefit level increase recognized Mr. Goodin's promotion to the president and chief executive officer position. The following table reflects our named executive officers' SISP levels as of December 31, 2013:

	December 31, 2013 Annual SISP Benefits	
Name	Survivor ($)	Retirement ($)
David L. Goodin	552,960	276,480
Doran N. Schwartz	233,184	116,592
J. Kent Wells	N/A	N/A
Jeffrey S. Thiede	N/A	N/A
Paul K. Sandness	328,080	164,040

Nonqualified Defined Contribution Plan

The company adopted the Nonqualified Defined Contribution Plan, or NQDCP, effective January 1, 2012, to provide deferred compensation for a select group of management or highly compensated employees who do not participate in the SISP. The compensation committee, upon recommendation from the chief executive officer, determines which employees will participate in the NQDCP for any year. The compensation committee determines the amount of employer contributions under the plan, which are credited to plan accounts and not funded. After satisfying a four-year vesting requirement for each contribution, the contributions and investment earnings will be distributed to the executive in a lump sum upon separation from service with the company or in annual installments commencing upon the later of (i) separation from service and (ii) age 65. The four-year vesting requirement is waived if the participant dies while employed by the company.

The committee, upon recommendation of the chief executive officer, selected Mr. Thiede as a participant for 2013 with an employer contribution of $33,000 or 10% of his base salary as of January 1, 2013. The contribution was awarded to recognize his promotion to president of the construction services segment and achievement of an annualized return on invested capital that was 4.7 percentage points higher than the weighted average cost of capital for the construction services segment. We believe that Mr. Thiede's participation in this plan and the four-year vesting requirement enhances retention since he cannot participate in any of our defined benefit retirement plans.

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 2013 satisfied the requirements for deductibility.

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, 2013:

Name	Assigned Guideline Multiple of Base Salary	Actual Holdings as a Multiple of Base Salary	Number of Years at Guideline Multiple (#)
David L. Goodin	4X	2.13	1.00(1)
Doran N. Schwartz	3X	2.54	3.87(2)
J. Kent Wells	3X	1.49	2.67(3)
Jeffrey S. Thiede	3X	0.15	(4)
Paul K. Sandness	3X	4.80	9.75

(1) Participant must meet ownership requirement by January 1, 2018.

(2) Participant must meet ownership requirement by January 1, 2015.

(3) Participant must meet ownership requirement by May 1, 2016.

(4) Participant must meet ownership requirement by January 1, 2019.

PROXY

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 2013 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 2013

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)
David L. Goodin	2013	625,000	–	1,241,280	–	1,610,625	532,991	37,517(3)	4,047,413
President and CEO	2012	–	–	–	–	–	–	–	–
	2011	–	–	–	–	–	–	–	–
Terry D. Hildestad	2013	74,481(4)	–	–	–	–	17,928	13,565(3)	105,974
President and CEO	2012	750,000	–	897,277	–	518,250	355,027	38,224	2,558,778
	2011	750,000	–	1,084,318	–	954,750	739,760	37,499	3,566,327
Doran N. Schwartz	2013	345,000	–	342,579	–	296,355	28,459	34,881(3)	1,047,274
Vice President and CFO	2012	300,000	–	179,445	–	103,650	100,935	34,224	718,254
	2011	273,000	–	197,341	–	173,765	147,789	33,549	825,444
J. Kent Wells	2013	570,000	–	1,509,419	–	1,425,000	–	20,556(3)	3,524,975
Vice Chairman of the	2012	550,000	–	877,331	–	–	–	96,470	1,523,801
Corporation and President and CEO of Fidelity Exploration & Production Company	2011	367,671	916,685(5)	925,000(6)	–	1,007,306(7)	–	84,580(8)	3,301,242
Jeffrey S. Thiede	2013	367,068	–	–	–	825,000	–	66,282(3)	1,258,350
President and CEO of	2012	–	–	–	–	–	–	–	–
MDU Construction Services Group, Inc.	2011	–	–	–	–	–	–	–	–
Paul K. Sandness	2013	344,000	–	387,138	–	354,595	–	39,131(3)	1,124,864
General Counsel and	2012	–	–	–	–	–	–	–	–
Secretary	2011	–	–	–	–	–	–	–	–

(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, 2013.

(2) Amounts shown represent the change in the actuarial present value for years ended December 31, 2011, 2012, and 2013 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, 2011, 2012, and 2013, as follows:

	Accumulated Pension Change			Above-Market Earnings		
Name	12/31/2011 ($)	12/31/2012 ($)	12/31/2013 ($)	12/31/2011 ($)	12/31/2012 ($)	12/31/2013 ($)
David L. Goodin	–	–	532,986	–	–	5
Terry D. Hildestad	728,587	331,845	(582,178)	11,173	23,182	17,928
Doran N. Schwartz	147,789	100,935	28,459	–	–	–
J. Kent Wells	–	–	–	–	–	–
Jeffrey S. Thiede	–	–	–	–	–	–
Paul K. Sandness	–	–	(170,904)	–	–	–

(3)

	401(k) ($)(a)	Life Insurance Premium ($)	Matching Charitable Contribution ($)	Automobile Allowance ($)	Additional LTD Premium ($)	Nonqualified Defined Contribution Plan ($)	Total ($)
David L. Goodin	36,975	242	300	–	–	–	37,517
Terry D. Hildestad	11,752	13	1,800	–	–	–	13,565
Doran N. Schwartz	34,425	156	300	–	–	–	34,881
J. Kent Wells	20,400	156	–	–	–	–	20,556
Jeffrey S. Thiede	20,400	156	–	12,000	726	33,000	66,282
Paul K. Sandness	36,975	156	2,000	–	–	–	39,131

(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) Mr. Hildestad's reported salary includes $65,827 of vacation payout.

(5) Includes a cash recruitment payment of $550,000 and guaranteed target annual incentive payment of $366,685.

(6) 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.

(7) 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.

(8) 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 2013

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards			Estimated Future Payouts Under Equity Incentive Plan Awards			All Other Stock Awards: Number of Shares of Stock or Units	All Other Option Awards: Number of Securities Underlying Options	Exercise or Base Price of Option Awards	Grant Date Fair Value of Stock and Option Awards
Name (a)	Grant Date (b)	Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	(#) (i)	(#) (j)	($/Sh) (k)	($) (l)
David L.	3/4/2013(1)	290,625	937,500	1,940,625	–	–	–	–	–	–	–
Goodin	3/4/2013(2)	–	–	–	8,558	42,788	85,576	–	–	–	1,241,280
Terry D.	–	–	–	–	–	–	–	–	–	–	–
Hildestad	–	–	–	–	–	–	–	–	–	–	–
Doran N.	3/4/2013(3)	53,475	172,500	357,075	–	–	–	–	–	–	–
Schwartz	3/4/2013(2)	–	–	–	2,362	11,809	23,618	–	–	–	342,579
J. Kent Wells	3/4/2013(1)	178,125	712,500	1,425,000	–	–	–	–	–	–	–
	3/4/2013(2)	–	–	–	10,406	52,031	104,062	–	–	–	1,509,419
Jeffrey S.	2/7/2013(3)	231,000	330,000	825,000	–	–	–	–	–	–	–
Thiede	–	–	–	–	–	–	–	–	–	–	–
Paul K.	3/4/2013(3)	63,984	206,400	427,248	–	–	–	–	–	–	–
Sandness	3/4/2013(2)	–	–	–	2,669	13,345	26,690	–	–	–	387,138

(1) Annual incentive for 2013 granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

(2) Performance shares for the 2013-2015 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

(3) Annual incentive for 2013 granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan.

Narrative Discussion Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Incentive Awards

Annual Incentive

On March 4, 2013, the compensation committee recommended the 2013 annual incentive award opportunities for our named executive officers, except for Mr. Thiede, and the board approved these opportunities at its meeting on March 4, 2013. Mr. Thiede's 2013 annual incentive award opportunity was established on February 7, 2013 by Mr. Goodin and the former chief executive officer of the construction services segment and was left unchanged by the compensation committee when he was promoted. These award opportunities are reflected in the Grants of Plan-Based Awards table at grant on March 4, 2013, (February 7, 2013 for Mr. Thiede) in columns (c), (d), and (e) and in the Summary Compensation Table as earned with respect to 2013 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. Based upon achievement of goals, actual payment may range from 0% to 207% of the target for Messrs. Goodin, Schwartz, and Sandness, from 0% to 200% of the target for Mr. Wells, and from 0% to 250% of the target for Mr. Thiede.

In order to be eligible to receive a payment of an annual incentive award under the Long-Term Performance-Based Incentive Plan, Messrs. Goodin and Wells must have remained employed by the company through December 31, 2013, 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. The application of any 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 Messrs. Schwartz, Thiede, and Sandness, participants who retire during the year at age 65 pursuant to their employer's bylaws 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. Goodin, Schwartz, and Sandness 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	208.8%	28.5%	59.5%
Exploration and Production Segment	200.0%	26.6%	53.2%
Pipeline and Energy Services Segment	50.0%	9.8%	4.9%
Electric and Natural Gas Distribution Segments	154.3%	35.1%	54.2%
Total (Payout Percentage)			171.8%

The award opportunity available to Mr. Wells was:

Exploration and Production's 2013 earnings* results as a % of 2013 target (weighted 75.0%)	Corresponding payment of annual incentive target based on earnings
Less than 90%	0%
90%	25%
100%	100%
101%	120%
102%	140%
103%	160%
104%	180%
105%	200%

MDU Resources Group, Inc.'s consolidated 2013 earnings per share results as a % of target (weighted 25%)	Corresponding payment of annual incentive target based on consolidated earnings per share result
Less than 85%	0%
85%	25%
90%	50%
95%	75%
100%	100%
103%	120%
106%	140%
109%	160%
112%	180%
115%	200%

* Earnings is defined as GAAP earnings reported for the exploration and production segment, adjusted to exclude the (i) effect on earnings of any noncash write-downs of oil and natural gas properties due to ceiling test impairment charges and any associated earnings benefit resulting from lower depletion, depreciation, and amortization expenses and (ii) the effect on earnings of any noncash gains and losses that result from (x) ineffectiveness in hedge accounting, (y) derivatives that no longer qualify for hedge accounting treatment, or (z) the discontinuation of hedge accounting treatment.

The award opportunity available to Mr. Thiede was:

Construction Services' 2013 earnings* results as a % of 2013 target (weighted 100%)	Corresponding payment of annual incentive target based on earnings
Less than 70%	0%
70%	70%
100%	100%
116%	130%
130%	160%
144%	190%
157%	220%
171%	250%

* Earnings is defined as GAAP earnings reported for the construction services segment.

For discussion of the specific incentive plan performance targets and results, please see the Compensation Discussion and Analysis.

Long-Term Incentive

On March 4, 2013, the compensation committee recommended long-term incentive grants to the named executive officers, except for Mr. Thiede, in the form of performance shares, and the board approved these grants at its meeting on March 4, 2013. 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 2013-2015 total stockholder return is positive, from 0% to 200% of the target grant will be paid out in February 2016, depending on our 2013-2015 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 March 4, 2013 Grant
75th or higher	200%
50th	100%
25th	20%
Less than 25th	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 2016 at the same time as the performance share awards are paid.

If the common stock of a company in the peer group ceases to be traded at any time during the 2013-2015 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 2013-2015 total stockholder return is negative, the number of shares otherwise earned, if any, for the performance period will be reduced in accordance with the following table:

Total Stockholder Return	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
David L. Goodin	625,000	–	4,047,413	15.4%
Terry D. Hildestad	74,481	–	105,974	70.3%
Doran N. Schwartz	345,000	–	1,047,274	32.9%
J. Kent Wells	570,000	–	3,524,975	16.2%
Jeffrey S. Thiede	367,068	–	1,258,350	29.2%
Paul K. Sandness	344,000	–	1,124,864	30.6%

Outstanding Equity Awards at Fiscal Year-End 2013

	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)
David L. Goodin	–	–	–	–	–	–	–	148,124(2)	4,525,188
Terry D. Hildestad	–	–	–	–	–	–	–	146,206(2)	4,466,593
Doran N. Schwartz	–	–	–	–	–	–	–	64,252(2)	1,962,899
J. Kent Wells	–	–	–	–	–	–	–	206,196(2)	6,299,288
Jeffrey S. Thiede	–	–	–	–	–	–	–	–	–
Paul K. Sandness	–	–	–	–	–	–	–	74,104(2)	2,263,877

(1) Value based on the number of performance shares reflected in column (i) multiplied by $30.55, the year-end closing price for 2013.

(2) Below is a breakdown by year of the plan awards:

Named Executive Officer	Award	Shares	End of Performance Period
David L. Goodin	2011	30,376	12/31/13
	2012	32,172	12/31/14
	2013	85,576	12/31/15
Terry D. Hildestad	2011	108,486	12/31/13
	2012	37,720	12/31/14
	2013	–	12/31/15
Doran N. Schwartz	2011	19,744	12/31/13
	2012	20,890	12/31/14
	2013	23,618	12/31/15
J. Kent Wells	2011	–	12/31/13
	2012	102,134	12/31/14
	2013	104,062	12/31/15
Jeffrey S. Thiede	2011	–	12/31/13
	2012	–	12/31/14
	2013	–	12/31/15
Paul K. Sandness	2011	24,156	12/31/13
	2012	23,258	12/31/14
	2013	26,690	12/31/15

Shares for the 2011 award are shown at the maximum level (200%) based on results for the 2011-2013 performance cycle above target.

Shares for the 2012 award are shown at the maximum level (200%) based on results for the first two years of the 2012-2014 performance cycle above target.

Shares for the 2013 award are shown at the maximum level (200%) based on results for the first year of the 2013-2015 performance cycle above target.

Pension Benefits for 2013

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)	Present Value of Accumulated Benefit ($) (d)	Payments During Last Fiscal Year ($) (e)
David L. Goodin	MDU Pension Plan	26	839,516	–
	SISP I(1)(3)	10	365,414	–
	SISP II(2)(3)	10	570,332	–
	SISP II 2012 Upgrade(4)	1	57,247	–
	SISP II 2013 Upgrade(4)	0	782,190	–
	SISP Excess(5)	26	30,865	–
Terry D. Hildestad	MDU Pension Plan	35	1,438,289	95,896
	SISP I(1)(3)	10	2,061,898	–
	SISP II(2)(3)	10	3,404,499	–
	SISP Excess(5)	35	192,720	182,410
Doran N. Schwartz	MDU Pension Plan	4	77,776	–
	SISP II(2)(3)	6	400,999	–
	SISP II 2013 Upgrade(4)	0	132,714	–
J. Kent Wells(6)	–	–	–	–
Jeffrey S. Thiede(6)	–	–	–	–
Paul K. Sandness	MDU Pension Plan	29	1,383,460	–
	SISP I(1)(3)	10	389,048	–
	SISP II(2)(3)	10	1,088,256	–
	SISP Excess(5)	29	153,245	–

(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, 2013, 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) Benefit level increases granted under SISP II on or after January 1, 2010 require an additional three years of vesting service for the increase. Mr. Goodin received a benefit increase effective January 1, 2012 and Messrs. Goodin and Schwartz received benefit level increases effective January 1, 2013; the present value of their accumulated benefits was calculated assuming that the additional vesting requirements would be met.

(5) The number of years of credited service under the SISP excess reflects the years of credited benefit service in the MDU pension plan as of December 31, 2009, when the MDU pension plan was frozen, rather than the years of participation in the SISP excess. We reflect years of credited benefit service in the MDU pension plan because the SISP excess provides a benefit that is based on benefits that would have been payable under the MDU pension plan absent Internal Revenue Code limitations.

(6) Messrs. Wells and Thiede are not eligible to participate in the MDU pension plan and do 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, 2013, calculated using a 4.32% and 4.48% discount rate for the SISP excess and MDU pension plan, respectively, the 2014 IRS Static Mortality Table for post-retirement mortality, and no recognition of future salary increases or pre-retirement mortality. The assumed retirement age for these benefits was age 60 for Messrs. Goodin, Schwartz, and Sandness. This is the earliest age at which the executives could begin receiving unreduced benefits. Mr. Hildestad's benefits reflect his actual retirement date of January 3, 2013. The amounts shown for the SISP I and SISP II were determined using a 4.32% discount rate and assume benefits commenced at age 65.

Pension Plan

Messrs. Goodin, Hildestad, Schwartz, and Sandness participate in the MDU Resources Group, Inc. Pension Plan for Non-Bargaining Unit Employees, which we refer to as the MDU pension plan. Pension benefits under the MDU pension plan 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 maximum years of service recognized when determining benefits under the pension plan is 35. Pension plan benefits are not reduced for social security benefits.

The MDU pension plan 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, participants must either remain employed until age 60 or elect to defer commencement of benefits until age 60. Mr. Hildestad was eligible for unreduced retirement benefits under the MDU pension plan. Participants whose employment terminates between the ages of 55 and 60, with 5 years of service under the MDU 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. 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 MDU pension plan 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. Goodin would have been eligible for a lump sum if he had retired on December 31, 2013.

The Internal Revenue Code limits the amounts paid under the MDU pension plan and the amount of compensation recognized when determining benefits. In 2009 when the MDU pension plan was frozen, the maximum annual benefit payable under the pension plan was $195,000 and the maximum amount of compensation recognized when determining benefits was $245,000.

Supplemental Income Security Plan

We also offer select key managers and executives benefits under our defined benefit nonqualified retirement plan, which we refer to as the Supplemental Income Security Plan or SISP. Messrs. Goodin, Hildestad, Schwartz, and Sandness participate in the 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. Two of the named executive officers, Messrs. Goodin and Schwartz, received a benefit level increase effective January 1, 2013, which requires three years of vesting.

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, 2013, 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. Goodin, in his upgrade, and Mr. Schwartz are fully vested in their SISP benefits, this would not result in any incremental benefit for the named executive officers other than Messrs. Goodin and Schwartz. The present value of these two additional years of service for Messrs. Goodin and 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. Mr. Sandness would be entitled to the SISP excess benefit if he was to terminate employment prior to age 65. Mr. Goodin must remain employed until age 60 to become entitled to his SISP excess benefit. Mr. Hildestad's benefits reflect his actual payment during 2013 as his retirement commenced before attainment of age 65 and the present value of his future payments that continue until he reaches age 65. Messrs. Schwartz, Wells, and Thiede 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 2013

Name (a)	Executive Contributions in Last FY ($) (b)	Registrant Contributions in Last FY ($) (c)	Aggregate Earnings in Last FY ($) (d)	Aggregate Withdrawals/ Distributions ($) (e)	Aggregate Balance at Last FYE ($) (f)
David L. Goodin	–	–	6	1,526	–
Terry D. Hildestad	–	–	46,850	–	1,048,483
Doran N. Schwartz	–	–	–	–	–
J. Kent Wells	–	–	–	–	–
Jeffrey S. Thiede	–	33,000	5,751	–	38,751(1)
Paul K. Sandness	–	–	–	–	–

(1) Includes $33,000 which was awarded to Jeffrey S. Thiede under the Nonqualified Defined Contribution Plan which is reported for 2013 in column (i) of the Summary Compensation Table in this proxy statement.

Deferral of Annual Incentive Compensation

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 2013 was 4.58% 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.

Nonqualified Defined Contribution Plan

The company adopted the Nonqualified Defined Contribution Plan, effective January 1, 2012, to provide deferred compensation for a select group of management or highly compensated employees who do not participate in the SISP. The compensation committee determines the amount of employer contributions under the Nonqualified Defined Contribution Plan, which are credited to plan accounts and not funded. After satisfying a four-year vesting requirement for each contribution, the contributions and investment earnings will be distributed to the executive in a lump sum upon separation from service with the company or in annual installments commencing upon the later of (i) separation from service and (ii) age 65. Plan benefits become fully vested if the participant dies while actively employed. Benefits are forfeited if the participant's employment is terminated for cause.

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 other than Mr. Hildestad, the information assumes the terminations and the change of control occurred on December 31, 2013. For Mr. Hildestad, the information relates to his actual retirement on January 3, 2013 and assumes that a change of control occurred on December 31, 2013. 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 include amounts under the Nonqualified Defined Contribution Plan, but do not include the named executive officers' deferred annual incentive compensation. See the Pension Benefits for 2013 table and the Nonqualified Deferred Compensation for 2013 table, and accompanying narratives, for a description of the named executive officers' accumulated benefits under our qualified defined benefit pension plans, the Nonqualified Defined Contribution Plan, and their deferred annual incentive compensation.

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 2013 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, 2013 for Mr. Sandness.

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. Goodin, Hildestad, Schwartz, Wells, and Sandness and the annual incentives for Messrs. Goodin and Wells, 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, 2013, Messrs. Goodin, Schwartz, and Wells had not satisfied this requirement. Accordingly, if a December 31, 2013 termination other than for cause without a change of control is assumed, the named executive officers' 2013-2015 performance share awards would be forfeited; any amounts earned under the 2012-2014 performance share award for Mr. Sandness would be reduced by one-third and such awards for Messrs. Goodin, Schwartz, and Wells would be forfeited; and any amounts earned under the 2011-2013 performance share award for Mr. Sandness would not be reduced and the awards for Messrs. Goodin and Schwartz would be forfeited. Mr. Wells had no 2011-2013 performance share awards, and Mr. Thiede had no 2013-2015, 2012-2014, or 2011-2013 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 2011-2013 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 193% of the target award. For the 2012-2014 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 2013-2015 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, 2013, 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, 2013.

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.

David L. Goodin

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)						937,500	937,500
2011-2013 Performance Shares						494,749	494,749
2012-2014 Performance Shares						513,465	513,465
2013-2015 Performance Shares						1,336,911	1,336,911
Benefits and Perquisites:							
Regular SISP(2)	930,586	930,586			987,517	930,586	
SISP Death Benefits(3)				6,118,589			
Disability Benefits(4)					107,847		
Total	**930,586**	**930,586**		**6,118,589**	**1,095,364**	**4,213,211**	**3,282,625**

(1) Represents the target 2013 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. Goodin's vested regular SISP benefit as of December 31, 2013, which was $12,145 per month for 15 years, commencing at age 65. Present value was determined using a 4.32% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2013 table. The amount payable for a disability reflects a credit for two additional years of vesting, which would result in full vesting of the 2012 SISP upgrade.

(3) Represents the present value of 180 monthly payments of $46,080 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 4.32% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2013 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 4.48% discount rate.

Terry D. Hildestad

Executive Benefits and Payments Upon Termination or Change of Control	Voluntary Termination ($) (1)	Not for Cause Termination ($)	For Cause Termination ($)	Death ($)	Disability ($)	Change of Control ($)
Compensation:						
2011-2013 Performance Shares	3,410,244					1,766,966
2012-2014 Performance Shares	602,011					602,011
2013-2015 Performance Shares						
Total	**4,012,255**					**2,368,977**

(1) Mr. Hildestad retired on January 3, 2013. The information in this table relates to his actual retirement on January 3, 2013, and assumes that a change of control occurred on December 31, 2013. The amount shown for the 2011-2013 Performance Shares is based on actual performance, resulting in payment of 193% of the target award. The amount shown for the 2012-2014 Performance Shares is the target award, prorated based on the number of months Mr. Hildestad worked during the performance period. His termination qualified as normal retirement under our qualified pension plan and our SISP. Mr. Hildestad also had an accumulated benefit under our Nonqualified Deferred Compensation Plan. These plans and Mr. Hildestad's benefits under them are described in the Pension Benefits for 2013 table and the Nonqualified Deferred Compensation for 2013 table and accompanying narratives.

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:							
2011-2013 Performance Shares						321,580	321,580
2012-2014 Performance Shares						333,404	333,404
2013-2015 Performance Shares						368,972	368,972
Benefits and Perquisites:							
Regular SISP	240,266(1)	240,266(1)			320,355(2)	240,266(1)	
SISP Death Benefits(3)				2,580,217			
Disability Benefits(4)					761,399		
Total	**240,266**	**240,266**		**2,580,217**	**1,081,754**	**1,264,222**	**1,023,956**

(1) Represents the present value of Mr. Schwartz's vested regular SISP benefit as of December 31, 2013, which was $4,380 per month for 15 years, commencing at age 65. Present value was determined using a 4.32% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2013 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 4.32% discount rate.

(3) Represents the present value of 180 monthly payments of $19,432 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 4.32% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2013 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 4.48% discount rate.

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)						712,500	712,500
2012-2014 Performance Shares						1,630,059	1,630,059
2013-2015 Performance Shares						1,625,709	1,625,709
Benefits and Perquisites:							
Disability Benefits (2)					399,567		
Total					**399,567**	**3,968,268**	**3,968,268**

(1) Represents the target 2013 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 the 4.32% discount rate applied for purposes of the SISP calculations. Though Mr. Wells is not a participant in the SISP, this rate is considered reasonable for purposes of this calculation as it would be applied if Mr. Wells were to become a SISP participant.

Jeffrey S. Thiede

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:							
Benefits and Perquisites:							
Nonqualified Defined Contribution Plan Death Benefit(1)				38,751			
Disability Benefits(2)					598,158		
Total				**38,751**	**598,158**		

(1) Represents the value of Mr. Thiede's unvested Nonqualified Defined Contribution Plan account at December 31, 2013, which would be paid upon death.

(2) Represents the present value of the disability benefit. Present value was determined using the 4.32% discount rate applied for purposes of the SISP calculations. Though Mr. Thiede is not a participant in the SISP, this rate is considered reasonable for purposes of this calculation as it would be applied if Mr. Thiede were to become a SISP participant.

Paul K. Sandness

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:							
2011-2013 Performance Shares	759,356	759,356		759,356	759,356	393,441	393,441
2012-2014 Performance Shares	247,476	247,476		247,476	247,476	371,198	371,198
2013-2015 Performance Shares						416,965	416,965
Benefits and Perquisites:							
Regular SISP(1)	1,437,027	1,437,027			1,437,027	1,437,027	
Excess SISP(2)	150,947	150,947			150,947	150,947	
SISP Death Benefits(3)				3,630,256			
Total	**2,594,806**	**2,594,806**		**4,637,088**	**2,594,806**	**2,769,578**	**1,181,604**

(1) Represents the present value of Mr. Sandness' vested regular SISP benefit as of December 31, 2013, which was $13,670 per month for 15 years, commencing at age 65. Present value was determined using a 4.32% discount rate. The terms of the regular SISP benefit are described following the Pension Benefits for 2013 table.

(2) The present value of all excess SISP benefits Mr. Sandness would be entitled to upon termination of employment under the SISP was computed based on calculations of ages rounded to the nearest whole age. Actual payments may differ. The terms of the excess SISP benefit are described following the Pension Benefits for 2013 table.

(3) Represents the present value of 180 monthly payments of $27,340 per month, which would be paid as a SISP death benefit under the SISP. Present value was determined using a 4.32% discount rate. The terms of the SISP death benefit are described following the Pension Benefits for 2013 table.

Director Compensation for 2013

Name (a)	Fees Earned or Paid in Cash ($) (b)	Stock Awards ($) (c)	Option Awards ($) (d)	Non-Equity Incentive Plan Compensation ($) (e)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (f)	All Other Compensation ($) (g)(1)	Total ($) (h)
Thomas Everist	65,000	110,000(2)	–	–	–	156	175,156
Karen B. Fagg	65,000	110,000(2)	–	–	–	656	175,656
Mark A. Hellerstein (3)	22,917	45,833(4)	–	–	–	65	68,815
A. Bart Holaday	55,000(5)	110,000(2)	–	–	–	156	165,156
Dennis W. Johnson	70,000	110,000(2)	–	–	–	156	180,156
Thomas C. Knudson	55,000	110,000(2)	–	–	–	156	165,156
Richard H. Lewis (6)	18,333	36,667(4)	–	–	–	481,572(7)	536,572
William E. McCracken (3)	22,917	45,833(4)	–	–	–	65	68,815
Patricia L. Moss	55,000	110,000(2)	–	–	–	156	165,156
Harry J. Pearce	138,750	110,000(2)	–	–	–	156	248,906
John K. Wilson	55,000(8)	110,000(2)	–	–	–	156	165,156

(1) Group life insurance premium and a matching charitable contribution of $500 for Ms. Fagg.

(2) Reflects the aggregate grant date fair value of 3,603 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 20, 2013, which was $30.528. The $7.62 in cash paid to each director for the fractional shares is included in the amounts reported in column (c) to this table.

(3) Elected a Director effective August 1, 2013.

(4) Reflects the aggregate grant date fair value 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 20, 2013, which was $30.528. The stock payment is pro-rated for directors who do not serve the entire calendar year. There were 1,501 shares purchased for Messrs. Hellerstein and McCracken with $10.80 in cash paid to each for the fractional shares, and for Mr. Lewis there were 1,201 shares purchased with $2.54 in cash paid to Mr. Lewis for the fractional share.

(5) Includes $54,977 that Mr. Holaday received in our common stock in lieu of cash.

(6) Mr. Lewis served on the board until April 23, 2013.

(7) Comprised of a group life insurance premium of $52, payments of $18,961 during 2013 from Mr. Lewis' deferred compensation and the value of Mr. Lewis' deferred compensation at December 31, 2013, which is payable over five years in monthly installments.

(8) Includes $54,977 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(1)	90,000
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(2)	110,000

(1) Increased from $75,000 to $90,000 effective June 1, 2013.

(2) 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 $156.

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 2013.

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 included in the 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 and internal control 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 the ratio of executive compensation to total stockholder return compared 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
- 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, earnings, 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	52	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.”
David C. Barney	58	Mr. Barney was elected president and chief executive officer of Knife River Corporation effective April 30, 2013; president effective January 1, 2012; and president of its western area operations effective October 2008. Prior to that, he was manager of its Northern California region effective July 2005 and became president of Concrete, Inc. in 1996. He joined Concrete, Inc. in 1986 and held numerous positions of increasing responsibility before it was acquired by Knife River in September 1993.
Steven L. Bietz	55	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	52	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	54	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.
Dennis L. Haider	61	Mr. Haider was elected executive vice president-business development effective June 1, 2013. Prior to that, he was executive vice president-business development and gas supply of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation and Intermountain Gas Company from January 1, 2012 to May 31, 2013; executive vice president-regulatory, gas supply, and business development of Cascade Natural Gas Corporation and Intermountain Gas Company from October 1, 2010 to December 31, 2011, and of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. from October 1, 2008 to December 31, 2011; executive vice president-business development and gas supply of Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. from August 1, 2005 to September 30, 2008. He joined Montana-Dakota Utilities Co. in 1978 and held numerous positions of increasing responsibility.
Douglass A. Mahowald	64	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	55	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	59	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.
Nathan W. Ring	38	Mr. Ring was elected vice president, controller and chief accounting officer effective January 3, 2014. Prior to that, he was treasurer and controller for MDU Construction Services Group, Inc. since late April 2013, was its treasurer from September 2012 through late April 2013 and was its controller from June 2012 until September 2012. Prior to that, he served as assistant controller of D S S Company, a subsidiary of Knife River Corporation, a subsidiary of the Company, from March 2009 to June 2012 and as controller of another Knife River Corporation subsidiary, Hap Taylor & Sons, Inc. doing business as Norm’s Utility Contractor, Inc., from March 2007 to March 2009. He joined MDU Resources Group, Inc. in 2001 as a tax analyst.

Paul K. Sandness	59	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.
Doran N. Schwartz	44	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	54	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.
Jeffrey S. Thiede	52	Mr. Thiede was elected president and chief executive officer of MDU Construction Services Group, Inc. effective April 30, 2013, and president effective January 1, 2012. Prior to that, he was president of Capital Electric Construction Company, Inc. effective July 2006, and president of Oregon Electric Construction, Inc. effective October 2004. Prior to joining the company, Mr. Thiede was a project director for DPR Construction and worked in the field as an inside wireman.
J. Kent Wells	57	Mr. Wells was elected vice chairman of the corporation 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, 2013.

Name	Common Shares Beneficially Owned(1)	Shares Held By Family Members(2)	Percent of Class	Deferred Director Fees Held as Phantom Stock(3)
Thomas Everist	1,139,193(4)		*	29,998
Karen B. Fagg	42,081		*	
David L. Goodin	43,477(5)(6)	8,317	*	
Mark A. Hellerstein	1,501		*	
Terry D. Hildestad	10,249		*	
A. Bart Holaday	46,646		*	
Dennis W. Johnson	84,470(7)	4,560	*	
Thomas C. Knudson	28,070		*	
William E. McCracken	1,501		*	
Patricia L. Moss	66,328		*	
Harry J. Pearce	221,620		*	49,323
Paul K. Sandness	53,996(5)		*	
Doran N. Schwartz	28,712(5)(8)	1,300	*	
Jeffrey S. Thiede	1,941(5)		*	
J. Kent Wells	27,743		*	
John K. Wilson	95,995		*	
All directors and executive officers as a group (26 in number)	2,155,227	20,584	1.1	79,321

* 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 1,070,000 shares of common stock acquired through the sale of Connolly-Pacific to us.

(5) Includes full shares allocated to the officer's account in our 401(k) retirement plan.

(6) The total includes 8,317 shares owned by Mr. Goodin's wife.

(7) Mr. Johnson disclaims all beneficial ownership of the 4,560 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	13,303,128(1)	7.00%
Common Stock	State Street Corporation State Street Financial Center One Lincoln Street Boston, MA 02111	9,956,410(2)	5.30%
Common Stock	The Vanguard Group 100 Vanguard Blvd. Malvern, PA 19355	11,949,283(3)	6.32%

(1) In a Schedule 13G/A, Amendment No. 4, filed on January 30, 2014, BlackRock, Inc. reports sole voting power with respect to 12,183,613 shares and sole dispositive power with respect to 13,303,128 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 Advisors, LLC, BlackRock Investment Management, LLC, BlackRock Investment Management (Australia) Limited, BlackRock Life Limited, BlackRock (Netherlands) B.V., BlackRock Fund Managers Ltd, BlackRock Asset Management Ireland Limited, BlackRock International Limited, BlackRock Investment Management (UK) Limited, BlackRock (Luxembourg) S.A., BlackRock Asset Management North Asia Limited and BlackRock Fund Management Ireland Limited.

(2) In a Schedule 13G, filed on February 3, 2014, 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., State Street Global Advisors, Asia Limited and SSARIS Advisors LLC.

(3) In a Schedule 13G/A, Amendment No. 1, filed on February 11, 2014, The Vanguard Group reports sole dispositive power with respect to 11,805,392 shares, shared dispositive power with respect to 143,891 shares and sole voting power with respect to 172,291 shares. These shares include 106,291 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 103,600 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.

John G. Harp, who was chief executive officer of MDU Construction Services Group, Inc. and Knife River Corporation until his retirement in late April 2013, and his brother, Michael D. Harp, are managing members of MOJO Montana, LLC, a Nevada limited liability company (MOJO), which has leased properties located in Kalispell and Billings, Montana, to an indirect subsidiary of the company 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, which expired June 30, 2013, for these properties that provide for our indirect subsidiary to pay a combined monthly rent of $9,508 to MOJO. In May 2013, after Mr. Harp had retired, the leases were amended to extend the term for two additional years, for a combined monthly rent of $8,823, with the option to renew the leases for one additional year, expiring June 30, 2016. Rent for the additional year is to be renegotiated based upon fair market value as determined by the parties.

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/proxystatement/corporate-governance. The board of directors has determined that current directors Thomas Everist, Karen B. Fagg, Mark A. Hellerstein, A. Bart Holaday, Dennis W. Johnson, Thomas C. Knudson (not standing for re-election), William E. McCracken, 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.

The board of directors previously determined that Richard H. Lewis, who did not stand for re-election at the 2013 annual meeting, had no material relationship with us and was independent in accordance with our director independence guidelines and the New York Stock Exchange listing standards during the time he was a director.

In determining director independence, the board of directors reviewed and considered information about any transactions, relationships, and arrangements between the independent directors and their immediate family members and affiliated entities on the one hand, and the company and its affiliates on the other, and in particular the following transactions, relationships, and arrangements:

- *Business relationships with entities with which a director is affiliated:* Purchase by the company in the ordinary course of business of cloud-based services for meeting SEC filing requirements from WebFilings, LLC, a company in which Mr. Everist is a limited partner who owns less than 1% of the company. Payments by the company to WebFilings in any of the last three fiscal years did not exceed the greater of $1 million or 2% of WebFilings' consolidated gross revenues. The transaction was entered into on substantially the same terms as those prevailing at the time for comparable transactions with non-affiliated entities.

- *Charitable contributions by the MDU Resources Foundation (Foundation) to nonprofit organizations, where a director, or a director's spouse, serves or has served as a director, chair, or vice chair of the board of trustees, trustee, or member of the organization or related entity:* Charitable contributions by the Foundation to Sanford Health Foundation (formerly known as Medcenter One Foundation), Billings Catholic School Foundation, Montana State University Foundation, the Denver Children's Advocacy Center, the University of North Dakota Foundation, Jamestown College and its foundation, the City of Dickinson, Colorado UpLift, and Alliance in Choice for Education. None of the contributions made to any of these nonprofit entities during the last three fiscal years exceeded in any single year the greater of $1 million or 2% of the relevant organization's consolidated gross revenues.
- *Ownership by directors of company stock:* Ownership by Mr. Everist, directly or indirectly, of approximately 1.14 million shares of company stock, which represents less than 1% of our outstanding common stock, at December 31, 2013, and approximately 1.89 million shares, which was 1% of our outstanding common stock, at December 31, 2012.

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 2013, 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/proxystatement/integrity-guide.

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 or the full board. 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 2013, the board of directors held eight meetings. Each director attended at least 75% of the combined total meetings of the board and the committees on which the director served during 2013. Director attendance at our annual meeting of stockholders is left to the discretion of each director. Three directors attended our 2013 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/proxystatement/board-charters. Our corporate governance guidelines are available at http://www.mdu.com/proxystatement/corporate-governance, and our Leading With Integrity Guide is also on our website at http://www.mdu.com/proxystatement/integrity-guide.

Nominating and Governance Committee

The nominating and governance committee met four times during 2013. The committee members are Karen B. Fagg, chairman, A. Bart Holaday, William E. McCracken, and Patricia L. Moss. Richard H. Lewis served on the committee until the 2013 annual meeting, when he did not stand for re-election. William E. McCracken joined the committee effective August 1, 2013.

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/proxystatement/corporate-bylaws. See also the section entitled "2015 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.

Since our 2013 annual meeting, Messrs. Hellerstein and McCracken were recommended to the nominating and governance committee and elected to the board effective August 1, 2013. Mr. Pearce, a non-employee director and our chairman of the board of directors, recommended Mr. McCracken, and Mr. Robert L. Nance, a former non-employee director and stockholder, recommended Mr. Hellerstein. The committee did not retain a search firm to identify or evaluate any nominee, and no fees were paid.

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 2013. The audit committee members are Dennis W. Johnson, chairman, Mark A. Hellerstein, A. Bart Holaday, and John K. Wilson. Richard H. Lewis served on the committee until the 2013 annual meeting when he did not stand for re-election. Mark A. Hellerstein joined the committee effective August 1, 2013. The board of directors has determined that Messrs. Johnson, Hellerstein, Holaday, Lewis (during the time he was on the committee), and Wilson are "audit committee financial experts" as defined by Securities and Exchange Commission regulations, and Messrs. Johnson, Hellerstein, Holaday, Lewis (during the time he was on the committee), 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 registered public accounting firm, 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 registered public accounting firm's qualifications and independence
  - the performance of our internal audit function and independent registered public accounting firm 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, 2013, the audit committee has (1) reviewed and discussed the audited financial statements with management; (2) discussed with the independent registered public accounting firm (the "Auditors") the matters required to be discussed by Public Company Accounting Oversight Board Auditing Standard No. 16, Communications with Audit Committees; (3) received the written disclosures and the letter from the Auditors required by applicable requirements of the Public Company Accounting Oversight Board regarding the Auditors' communications with the audit committee concerning independence, and has discussed with the Auditors their 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, 2013, for filing with the Securities and Exchange Commission.

Dennis W. Johnson, Chairman
Mark A. Hellerstein
A. Bart Holaday
John K. Wilson

Compensation Committee

The compensation committee met five times during 2013. 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
- assist the board in overseeing the management of risk in the committee's areas of responsibility and
- appoint, compensate, and oversee the work of any compensation consultant, legal counsel or other adviser retained by the compensation committee.

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 did not retain a compensation consultant in 2013 to prepare a competitive assessment for 2014 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 2013, the vice president-human resources and the human resources department prepared the 2014 competitive assessment covering our Section 16 officers. The vice president-human resources and the human resources department also worked with the chief executive officer to:

- recommend salary grade midpoints, base salaries, annual and long-term incentive targets, benefit level increases under our Supplemental Income Security Plan, and employer contributions under our Nonqualified Defined Contribution Plan for our executive officers other than the chief executive officer and the vice president-human resources
- review recommended base salary grades, salary increases, and annual and long-term incentive targets submitted by executive officers for officers reporting to them for reasonableness and alignment with company or business segment objectives
- review and update annual and long-term incentive programs
- construct a recommended 2014 salary grade structure and
- verify the competitiveness of short-term and long-term incentive targets associated with salary grades and recommended modifications as appropriate.

As discussed in the Compensation Discussion and Analysis, Mr. Goodin recommended compensation for Mr. Thiede for the remainder of 2013 in connection with his promotion.

The compensation committee has sole authority to retain or obtain the advice of compensation consultants, legal counsel or other advisers to assist in consideration of the compensation of the chief executive officer, the other Section 16 officers, and the board of directors. The committee is directly responsible for the appointment, compensation and oversight of the work of any adviser retained by the committee. Prior to retaining an adviser and annually, the committee will consider all factors relevant to the adviser's independence from management. 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 2013.

Annually the compensation committee conducts an assessment of any potential conflicts of interest raised by the work of any compensation consultant to determine if any conflict exists and how such conflict should be addressed. 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 2013.

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.

In an engagement letter dated March 14, 2013, and signed by the chairman of the compensation committee, the compensation committee retained Towers Watson to prepare the 2013 compensation review for the board of directors. In its review of board of director compensation, Towers Watson was asked to:

- identify market trends relative to director compensation
- report on the competitive position of our director compensation program as compared to our performance graph peer group
- recommend alternatives for our board of directors to consider and
- research our performance graph peer group companies to identify practices relating to director recruitment, such as one-time stock grants upon election to the board.

At its May 2013 meeting, the committee reviewed Towers Watson's analysis of competitive data and recent trends in director compensation. The analysis compared our director compensation to that of our performance graph peer group, including the components of director compensation: retainer, committee chair premiums, and equity. The Towers Watson report showed the company's median total direct compensation, which includes the annual cash retainer, board fees, if applicable, and equity compensation, was at the 38th percentile at $165,000, versus the market median of the performance graph peer group of $170,084. Additionally, the company's committee chair premiums of $15,000, $10,000, and $10,000 for audit, compensation, and nominating/governance, respectively, approximated the median committee chair premiums of the performance graph peer group of $14,500, $10,000, and $8,000, respectively. Based on these results, the compensation committee recommended, and the board of directors approved, no change to director compensation or the committee chair premiums for 2013.

The human resources department augmented Towers Watson's report by showing a three-year history (2011, 2012, and 2013) of the non-executive chairman of the board's total direct compensation as compared to that of our performance graph peer group companies compiled by Equilar. Also, the human resources department's analysis included a two-year history (2012 and 2013) of the non-executive chairman's total direct compensation compared to total direct compensation for non-executive chairmen at "large companies" included in the National Association of Corporate Directors (NACD) Director Compensation Report, which have revenues ranging from $2.5 billion to $10 billion and a median revenue of $4.7 billion. The human resources department compared the total direct compensation in 2011, 2012, and 2013 of $240,000 for the company's non-executive chairman to the median total direct compensation of performance graph peer companies of $272,754, $282,202, and $239,511 for 2011, 2012, and 2013, respectively. Also, the total direct compensation for the company's non-executive chairman of $240,000 for 2012 and 2013 was below the median compensation for non-executive chairmen at large companies in the NACD Director Compensation Report.

Based on the competitive data, management recommended to the compensation committee that the non-executive chairman's additional retainer be increased from $75,000 to $90,000, effective June 1, 2013, which on an annual basis would reduce the difference between our non-executive chairman's 2013 total direct compensation and the median total direct compensation for non-executive chairman at large companies in the NACD Director Compensation Report. The compensation committee and the board of directors approved the increase in the non-executive chairman's additional retainer, resulting in an increase in his total direct compensation from $240,000 annually to $255,000 annually. The non-executive chairman of the board was not present during the compensation committee's discussion of the report developed by the human resources department and did not vote in approving the recommendation.

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 2013 or written representations that no Forms 5 were required, we believe that all such reports were timely filed, except that in August 2013, Mr. Dennis L. Haider filed an amended Form 3 to report ownership of 3,059 additional shares held in the company's direct registration system that were omitted from his original Form 3 filed in June 2013.

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.

2015 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 28, 2015, any stockholder who wishes to submit a nomination must submit the required notice to the corporate secretary on or before January 22, 2015.

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 28, 2015, 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 22, 2015.

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 28, 2015, stockholders must submit such written notice to the corporate secretary on or before January 22, 2015.

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 28, 2015, 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 12, 2014.

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/proxystatement/corporate-bylaws.

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, 2013, 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

Paul K. Sandness
Secretary
March 12, 2014

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EXHIBIT A

Towers Watson 2011 CDB General Industry Executive Database

3M
A.O. Smith
Abbott Laboratories
AbitibiBowater
Accenture
ACH Food
Acuity Brands
Adecco
Aerojet
Agilent Technologies
Agrium
Air Liquide
Air Products and Chemicals
Alcoa
Alcon Laboratories
Alexander & Baldwin
Alliant Techsystems
American Crystal Sugar
American Sugar Refining
AMERIGROUP
AmerisourceBergen
AMETEK
Amgen
Ann Taylor Stores
AOL APL
Appleton Papers
Applied Materials
ARAMARK
Armstrong World Industries
Arrow Electronics
Ashland
AstraZeneca
AT&T
Automatic Data Processing
Avery Dennison
Avis Budget Group
BAE Systems
Ball
Barnes Group
Battelle Memorial Institute
Baxter International
Bayer AG
Bayer CropScience
Beckman Coulter
Belo
Bemis
Benjamin Moore
Best Buy
Big Lots
Boeing
Boston Scientific
Bovis Lend Lease
Brady
Bristol-Myers Squibb
Broadridge Financial Solutions
Brown-Forman
Bucyrus International
Bunge
Burlington Northern Santa Fe
Bush Brothers
CA
Calgon Carbon
Cameron International
Cardinal Health
Cargill
Carlson Companies
Carmeuse North America Group
Carnival
Carpenter Technology
Caterpillar
CDI
CF Industries
CGI Technologies & Solutions
Chattem
Chemtura
Chiquita Brands
Choice Hotels International
Chrysler
CHS
Cisco Systems
Cliffs Natural Resources
COACH
Coca-Cola
Coca-Cola Enterprises
Coinstar
Colgate-Palmolive
Comcast
ConAgra Foods
Continental Automotive Systems
ConvaTec
Convergys
Cooper Industries
CoreLogic
Corning
Covance
Covidien
CSR
CSX
Curtiss-Wright
CVS Caremark
Cytec
Daiichi Sankyo
Daimler Trucks North America
Dannon
Darden Restaurants
Dassault Systems
Day & Zimmermann
Dean Foods
Deckers Outdoor
Dell
Delta Air Lines
Deluxe
Dentsply
Dex One
Diageo North America
Dollar Tree Stores
Domtar
Donaldson
Dow Corning
DuPont
Eastman Chemical
Eastman Kodak
Eaton
eBay
Ecolab
Eli Lilly
EMC
EMD Millipore
Endo Pharmaceuticals
Equifax
Equity Office Properties
Ericsson
Estee Lauder
Evergreen Packaging
Experian Americas
Express Scripts
Fair Isaac
Federal-Mogul
Fidelity National Information Services
Fiserv
Fluor
Ford
Fortune Brands
GAF Materials
Gavilon
General Atomics
General Dynamics
General Mills
General Motors
Genzyme
GlaxoSmithKline
Goodman Manufacturing
Goodrich
Google
Graco
Greif
Grupo Ferrovial
GSI Commerce
GTECH H.B. Fuller
Hanesbrands
Harland Clarke
Harley-Davidson
Harman International Industries
Hasbro
Haynes International
HBO
HD Supply
Headway Technologies
Herman Miller
Hershey
Hertz
Hewlett-Packard
Hexcel
Hilton Worldwide
Hitachi Data Systems
HNI HNTB
Hoffmann-La Roche
Holcim
Home Depot
Honeywell
Hormel Foods
Hostess Brands
Houghton Mifflin Harcourt Publishing
Hunt Consolidated
Huron Consulting Group
Husky Injection Molding Systems
Hyatt Hotels
IBM
IDEXX Laboratories
IKON Office Solutions
Illinois Tool Works
IMS Health
Ingersoll Rand
Intel
Intercontinental Hotels
International Flavors & Fragrances
International Paper
Interpublic Group
Intrepid Potash
Invensys Controls
ION Geophysical
Irvine Company
ITT
ITT Mission Systems
J.M. Smucker
J.R. Simplot
Jabil Circuit
Jack in the Box
JetBlue
JM Family Enterprises
Johns-Manville

Johnson & Johnson
Johnson Controls
Kaman Industrial Technologies
Kansas City Southern
Kao Brands
KBR Kellogg
Kimberly-Clark
Kinetic Concepts
Kinross Gold
Koch Industries
Kohler
Komatsu America
L-3 Communications
Land O'Lakes
Level 3 Communications
Lexmark International
Life Technologies
Linde
Lockheed Martin
Lorillard Tobacco
Lubrizol
Lyondell Chemical
Magellan Midstream Partners
ManTech International
Marriott International
Martin Marietta Materials
Mary Kay
Mattel
Matthews International
McClatchy
McDonald's
McGraw-Hill
McKesson
MDC Holdings
MeadWestvaco
Media General
Medicines Company
Medtronic
Merck & Co.
Microsoft
Milacron
Mitsubishi Power Systems Americas
Molson Coors Brewing
Momentive Specialty Chemicals
Monsanto
Mosaic
Motorola Mobility
Motorola Solutions
Murphy Oil
MWH Global
Navistar International
NCR
Nestlé USA
Newmont Mining
NewPage
Nissan North America
Nokia
Noranda Aluminum
Norfolk Southern
Novartis
Novartis Consumer Health
Novo Nordisk Pharmaceuticals
Nypro
Occidental Petroleum
Office Depot
Omnicare
Orange Business Services
Oshkosh
Overhead Door
Owens Corning
Owens-Illinois
Oxford Industries
Panasonic of North America
Parker Hannifin
Parsons
Performance Food Group
PerkinElmer
Pfizer
Pitney Bowes
Plexus
Polaris Industries
Potash
PPG Industries
Praxair
ProBuild Holdings
Pulte Homes
Purdue Pharma
QUALCOMM
Quintiles
R.R. Donnelley
Ralcorp Holdings
Reader's Digest
Realogy
Reddy Ice
Regal-Beloit
Regency Centers
Rent-A-Center
Research in Motion
Ricardo
Rio Tinto
Roche Diagnostics
Rockwell Automation
Rockwell Collins
Ryder System
Safety-Kleen Systems
SAIC
Sanofi-Aventis
SCA Americas
Schreiber Foods
Schwan's
Scotts Miracle-Gro
Scripps Networks Interactive
Seagate Technology
Sealed Air
ServiceMaster
ShawCor
Sherwin-Williams
Siemens AG
Sigma-Aldrich
Smith & Nephew
Snap-On
Sodexo
Sonoco Products
Space Systems Loral
Spirit AeroSystems
SprintNextel
SPX
SRA International
Stantec
Starbucks
StarTek
Starwood Hotels & Resorts
Statoil
Steelcase
Stryker
Sulzer Pumps US
SunGard Data Systems
Sunoco
Sunovion Pharmaceuticals
SuperValu Stores
Swagelok
Syngenta Crop Protection
Takeda Pharmaceutical
Taubman Centers
TE Connectivity
Tektronix
Temple-Inland
Teradata
Terex
Textron
Thermo Fisher Scientific
Thomas & Betts
Time Warner
Time Warner Cable
Timken
T-Mobile USA
Toro
Total System Services
Travelport
Trident Seafoods
TRW Automotive
Tupperware
Tyson Foods
U.S. Foodservice Underwriters Laboratories
Unilever United States
Union Pacific
Unisys
United Rentals
United States Cellular
United States Steel
United Technologies
URS Energy & Construction
USG
UTi Worldwide
Valero Energy
Vangent
Verde Realty
Verizon
Viacom
Vision Service Plan
Visteon
Vulcan Materials
VWR International
Walt Disney
Waste Management
Wendy's/Arby's Group
Weyerhaeuser
Whirlpool
Wilsonart International
Winnebago Industries
Wm. Wrigley Jr.
Wyndham Worldwide
Xerox
YRC Worldwide
Yum! Brands

Towers Watson 2011 CDB Energy Services Executive Database

Acciona
AGL Resources
Allete
Alliant Energy
Ameren
American Electric Power
Areva
ATC Management
Avista
BG US Services
Black Hills
California Independent System Operator
Calpine
CenterPoint Energy
CH Energy Group
Cleco
CMS Energy
Colorado Springs Utilities
Consolidated Edison
Constellation Energy
Covanta Holdings
CPS Energy
Crosstex Energy

PROXY

DCP Midstream
Dominion Resources
DPL
DTE Energy
Duke Energy
Edison International
EDP Renewables North America LLC
El Paso Corporation
El Paso Electric
Enbridge Energy
Energen
Energy Future Holdings
Energy Northwest
Entergy
EQT Corporation
ERCOT
Exelon
FirstEnergy
First Solar
GenOn Energy
Hawaiian Electric
Iberdrola Renewables
IDACORP
Integrys Energy Group
IPR – GDF SUEZ North America
ISO New England
Kinder Morgan
LES
LG&E and KU Energy Services
Lower Colorado River Authority
McDermott
MDU Resources
MGE Energy
MidAmerican Holdings
Midwest Independent Transmission System Operator
New York Independent System Operator
New York Power Authority
NextEra Energy
Nicor
Northeast Utilities
NorthWestern Energy
NRG Energy
NSTAR
Nuscale Power
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
Salt River Project
Santee Cooper
SCANA
SemGroup
Sempra Energy
Southern Company Services
Southern Union Company
Southwest Power Pool
Spectra Energy
STP Nuclear Operating
TECO Energy
Tennessee Valley Authority
Trans Bay Cable
TransCanada
UIL Holdings
UniSource Energy
Unitil
Vectren
Westar Energy
Westinghouse Electric
Williams Companies
Wisconsin Energy
Wolf Creek Nuclear
Xcel Energy

Towers Watson 2011 CSR Report on Top Management Compensation

AAA
AAR Corporation
ABB
ABX Air
Acuity
Acushnet
Advance Auto Parts
Adventist Health System
AEGON
AFLAC
AgFirst
Alfa Laval
Allegiance Health
Allete
Alta Resources
Altegrity
American Cancer Society
American Career College
American Enterprise
American Greetings
American Red Cross
American Textile
American Water Works
AmeriPride Services
Ameristar Casinos
Ames True Temper
AMETEK/Advanced Measurement Technology
Amica Mutual Insurance
Analytic Services (ANSER)
Andersen Corporation
ANH Refractories
AOC
Asahi Kasei Plastics NA
Ascend Performance Materials
Assurant
Aurora Healthcare
Auto Club Group
Automobile Club of Southern California
Avis Budget Group
Avista
Barloworld Handling
Baxa
Baxter International
Baylor College of Medicine
Baylor Health Care System
B Braun Medical
BE Aerospace
Beam Global Spirits & Wine
Belk
Bemis
Beneficial Bank
Berwick Offray
Biomet
Black Hills
BlueCross BlueShield of Louisiana
BlueCross BlueShield of Nebraska
BlueCross BlueShield of South Carolina
BlueCross BlueShield of Tennessee
Blue Cross of Northeastern Pennslyvania
Blue Cross of Idaho
Bosch Rexroth
Boyd Gaming
Boy Scouts of America
Bradley
Brady
Bridgepoint Education
Briggs & Stratton
Brightpoint North America
Brookdale Senior Living
Brownells
Bryant University
Buffets
Cablevision Systems
Caelum Research Corporation
Caesar's Entertainment
California Casualty Management
California Dental Association
California Institute of Technology
CareFirst BlueCross BlueShield
Carle Foundation Hospital
Carlson
CarMax
Carpenter Technology
CB Richard Ellis
Cell Therapeutics
CEMEX
CEVA Logistics
Chelan County Public Utility District
Chicago Transit Authority
Chickasaw Nation
Chico's FAS
Children's Healthcare of Atlanta
Choice Hotels International
CHS
CH2M Hill
Chumash Employee Resource Center
CIGNA
City of Austin
City of Chicago
City of Garland
City of Houston
City of Las Vegas
City of Philadelphia
Classified Ventures
Cleco
ClubCorp
CNL Financial Group
Cobb County School District
Coca-Cola Enterprises
College of St. Scholastica
Colman Group
Colorado Springs Utilities
Colsa
CommIT Enterprises
CommScope
Community Coffee
Community Health Network
Compressor Controls
Computer Sciences Consulting Group
Computer Task Group
ConnectiCare Capital LLC
Core Laboratories
Cornell University
Correctional Medical Services
Country Financial
Coventry Health Care
CPS Energy
Cracker Barrel Old Country Stores
Crate & Barrel
Crown Castle
CUNA Mutual
D&B
Decurion

Delta Dental Plan of Michigan
Denny's
DENSO International
DePaul University
Devry
Dickstein Shapiro
Diebold
Discover Financial Services
Doherty Employer Services
Dollar General
Dollar Tree Stores
Domino's Pizza
Donaldson
DSC Logistics
Duke Realty
Duke University & Health System
DuPont
Dupont Fabros Technology
Dyn McDermott
Edison Mission Energy
Education Management
Edward Jones
Edwards Lifesciences
Elizabeth Arden
EMCOR Group
Emerson Climate Technologies
Emerson Electric
Enpro Industries (Fairbanks Morse Engine)
Erickson Retirement Communities
Erie Insurance
ESCO Technologies
ESM
Esterline Technologies
Etnyre International
Evraz
Exel
Express Scripts
Fairfield Manufacturing
Farm Credit Bank of Texas
Farm Credit Foundations
Farmland Foods
Federal Reserve Bank of Atlanta
Federal Reserve Bank of Chicago
Federal Reserve Bank of Dallas
Federal Reserve Bank of Minneapolis
Federal Reserve Bank of Philadelphia
Federal Reserve Bank of Richmond
Federal Reserve Bank of St. Louis
Federal Reserve Board
FedEx Express
FedEx Ground
Ferguson Enterprises
Fermi National Accelerator Laboratory
Ferrellgas
First American
First Citizens Bank
First Commonwealth Financial
First Solar
Fiserv
Fiskars Brands
Fleetwood Group
Flexcon Company
Flexible Steel Lacing
Fortune Brands
Freeman Dallas
Friendly Ice Cream
Froedtert Hospital
Funeral Directors Life Insurance Company
Gaylord Entertainment
General Dynamics Information Technology
Genesis Energy
GenOn Energy
Gentiva Health Services
Georg Fischer Signet
Georgia Institute of Technology
Gerdau AmeriSteel
Gibraltar Steel Corporation
G&K Services
Glatfelter
GNC
Godiva Chocolatier
Gold Eagle
Graco
Graham Packaging
Grande Cheese
Grange Life Insurance
Great American Insurance
Greyhound Lines
Grinnell Mutual Reinsurance
GROWMARK
GTECH
GuideStone Financial Resources
Habitat for Humanity International
Harman International Industries
Harris County Hospital District
Harvard Vanguard Medical Associates
Harvey Industries
Haynes International
Hazelden Foundation
HD Supply
Health Care Services
HealthNow New York
H.E.B. Grocery
Hendrick Medical Center
Hendrickson International
Henry Ford Health Systems
Herman Miller
Highlights for Children
Highmark
Hill Phoenix
Hilti
Hilton Worldwide
Hines Interests
Hitachi America
HNI
HNTB
Houston Metropolitan Transit Authority
Hu-Friedy Manufacturing Company
Humana
Hunter Industries
Hutchinson Technology
Hyundai Capital America
Hyundai Motor America
Hyundai Motor Manufacturing of Alabama
IDEX Corporation
IDEXX Laboratories
II-VI
IKON Office Solutions
Indiana Farm Bureau Insurance
Infogroup
Information Management Service
Ingram Industries
Insperity
Institute for Defense Analyses
Integra Lifesciences Corporation
Intertape Polymer Group
Iron Mountain
Irvine
Isuzu Motors America
Ithaca College
Ithaka Harbors
Itochu International
ITT Industries – Information Systems
ITT Mission Systems
Jabil Circuit
Jackson Hewitt
Jacobs Technology
Jarden
Jefferson Science Associates
J J Keller & Associates
J&J Worldwide Services
JM Family Enterprises
John Crane
Johns Hopkins University
Johnson Controls
Johnson Financial Group
Johnson Outdoors
John Wiley & Sons
Joint Commission
Jones Lang LaSalle
Joy Global
J.R. Simplot
Kewaunee Scientific Corporation
Keystone Automotive Industries
Keystone Foods
KI
Kindred Healthcare
Kingston Technology
Klein Tools
Komatsu America
Kroger
Laboratory Corporation of America
Lake Region Medical
Lantech.com
Lawson Products
Learning Care Group
Legal & General America
Leggett and Platt
Leo Burnett
LG&E and KU Energy Services
Lieberman Research Worldwide
Limited Brands
Littelfuse
Little Lady Foods
L.L. Bean
Logic PD
Louisiana-Pacific
Lower Colorado River Authority
Loyola University of Chicago
Lozier
LSG Sky Chefs
Luck Stone
Lutron Electronics
Luxottica Retail
La Macchia Enterprises
Magellan Health Services
Magna Seating
Malco Products
Maricopa County Office of Management & Budget
Maricopa Integrated Health System
Marshfield Clinic
Mars North America
Mary Kay
MasterBrand Cabinets
Master Lock
Mayo Clinic
McCain Foods USA
McGladrey
Medco Health Solutions
Media General
Medica Health Plans
Medical Group Management Assn
Mercedes-Benz Financial Services
Mercer University
Merit Medical Systems
Merrill
Methodist Healthcare System
MetLife
Metropolitan Atlanta Rapid Transit Authority
Miami Children's Hospital
Mine Safety Appliances
Miniature Precision Comps
Minnesota Management & Budget
Missouri Department of Conservation

Missouri Department of Transportation
Mitsubishi International
Mitsui U S A.
Molex
Moneris Solutions
MSC Industrial Direct
MTD Products
MTS Systems
Mueller Water Products
MultiPlan
Mutual of Omaha
Mylan
Nash-Finch
National Academies
National Futures Association
National Interstate Insurance
National Safety Council
Nature's Sunshine Products
Navistar International
Navy Exchange Service Command
NCCI Holdings
NCMIC
North Carolina State Employees' Credit Union
Nebraska Public Power District
Neenah Paper
NewPage
New York Community Bank
NextEra Energy
Nicor
Nielsen
NiSource
NJM Insurance Group
NJVC LLC
Nordson Corporation
Nordstrom Bank
North Texas Tollway Authority
Northwestern Memorial Hospital
Northwestern Mutual
NuStar Energy
OfficeMax
Ohio Public Employees Retirement System
Ohio State University
Ohio State University Medical Center
OHL
Old Dominion Electric
Oncology Nursing Society
One America Financial Partners
1st Source
Oppenheimer Group
Opus Bank
Orbital Science Corporation
Oshkosh
Pall Corporation
Pampered Chef
Panduit Corporation
Patterson Companies
Paychex
Pearson
Penn National Gaming
Penn State Hershey Medical Center
Pharmavite
PHH Arval
Pier 1 Imports
PMA Companies
Polaris Industries
Policy Studies
Polymer Technologies
Popular
Port of Portland
Poudre Valley Health Systems
Preformed Line Products
Premera Blue Cross
Premier
PREMIER Bankcard
Principal Financial
Professional Golfers' Association of America
Progressive
Project Management Institute
Prometric Inc
Property Casualty Insurers
Association of America
Publix Super Markets
Purdue Pharma
QBE the Americas
QSC Audio Products
Qualex
Qualis Health
Quality Bicycle Products
Quest Diagnostics
QVC
Radio One
RadioShack
Recology
Regence Group
Regency Centers
Regions Financial
Reinsurance Group of America
Renaissance Learning
RiceTec
Rice University
Rich Products
Ricoh Electronics
Rite – Hite Holding Corporation
Robert Bosch
Rollins
R.R. Donnelley
RSC Equipment Rental
Ryland Group
Safety-Kleen Systems
Sakura Finetek USA
Salk Institute
Salt River Project
Samuel Roberts Noble Foundation
San Antonio Water System
San Manuel Band of Mission Indians
Sauer-Danfoss
S&C Electric
Schaumburg Township District Library
Schneider Electric
Schwan Food
Scooter Store
Sealed Air
Sealy
Seco Tools
Securus Technologies
SEMCO Energy
Sentara Healthcare
Serco
Shands HealthCare
Sharp Electronics
Simon Property Group
Simpson Housing
SIRVA
Smead Manufacturing
SMSC Gaming Enterprise
Sole Technology
Solo Cup
Southco
Southeastern Freight Lines
South Jersey Gas
Southwest Gas
Space Dynamics Laboratory
Space Telescope Science Institute
Spectrum Health – Grand Rapids Hospitals
Spinmaster
SPX Corporation
Stampin' Up!
Standard Motor Products
Staples
State Corporation Commission
State Personnel Administration
St. Cloud Hospital
Steelcase
Sterilite
Sterling Bancshares
St. Jude Children's Research Hospital
St. Louis County Government
Stonyfield Farm
St. Vincent Hospital
Subaru of Indiana Automotive
Sykes Enterprises
Syncada
Synthes
Tastefully Simple
Taubman
Taylor
TDS Telecom
Tech Data
Technicolor
Tecolote Research
Tele-Consultants
Tennant Company
Texas Industries
Texas Mutual Insurance
Therma Tru
Thule
Timberland
TIMET
TJX Companies
Total System Services
Transocean
Travis County
Treasure Island Resort & Casino
Tri-Met
Trinity Consultants
Trinity Health
TriWest Healthcare Alliance
True Value Company
Tufts Health Plan
Turner Broadcasting
UDR
UMDNJ-University of Medicine & Dentistry
Underwriters Laboratories
United American Insurance
UnitedHealth
United States Steel
United Stationers
Universal Studios Orlando
University Health System
University of Alabama at Birmingham
University of California, Berkeley
University of Chicago
University of Georgia
University of Houston
University of Kansas Hospital
University of Maryland Medical Center
University of Miami
University of Michigan
University of Nebraska-Lincoln
University of North Texas
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
at Houston
University of Wisconsin Medical Foundation
University of Wisconsin Hospital and Clinics
University Physicians
UPS
URS
USAA
U.S. Foodservice

USG
Utah Transit Authority
UT Southwestern Medical Center
Vail Resorts Management
Valpak/Cox Target Media
Valspar
Ventura Foods
Venturedyne
Verde Realty
Vermeer Manufacturing Company
Vesuvius USA
VF
Via Christi Health
Viad
Vi-Jon
Virginia Farm Bureau Insurance Sevice
Visiting Nurse Service of NY
Volvo Group North America
Wackenhut Services
Walgreen Co.
Washington University in St. Louis
Wawa
Wayne Memorial Hospital
W C Bradley
Wellcare Health Plans
Wellmark BlueCross BlueShield
Wells' Dairy
Werner
West Bend Mutual Insurance
Western Southern Financial Group
Western Union Company
Westfield Group
Weston Solutions
West Penn Allegheny Health System
West Virginia University Hospitals
Wheaton Franciscan Healthcare
Wheels
Whirlpool
Whole Foods Market
Wilder Foundation
WilmerHale LLP
Wilsonart International
Windstream Communications
Winn-Dixie Stores
Wisconsin Physicians Service Insurance
World Vision International
World Vision United States
Worthington Industries
Wyle Laboratories
Yamaha Corporation of America
YKK Corporation of America
YSI
Zale
Zebra Technologies Corporation
Zimmer

Mercer's 2011 Total Compensation Survey for the Energy Sector

Abraxas Petroleum Corporation
Advanced Drilling Technologies, LLC
Afren Resources USA, Inc.
AGL Resources
AGL Resources – Sequent Energy Management
Aker Solutions
Alliance Pipeline, Inc.
Alliant Energy
Alyeska Pipeline Service Company
Ameren Corporation
Ameren Corporation – Ameren Illinois
Ameren Corporation – Ameren Missouri
Ameren Corporation – AmerenEnergyResources
American Transmission Company
Apache Corporation
Arch Coal, Inc.
Associated Electric Cooperative, Inc.
Atlas Energy, L.P.
Baker Hughes, Inc.
Baker Hughes, Inc. – Completion and Production
Baker Hughes, Inc. – Drilling and Evaluation
Baker Hughes, Inc. – Gulf of Mexico
Baker Hughes, Inc. – Integrated Operations
Baker Hughes, Inc. – Intelligent Production Systems
Baker Hughes, Inc. – Reservior Development Services
Baker Hughes, Inc. – US Land
Basic Energy Services
Baytex Energy USA Ltd.
BG US Services
BHP Billiton Petroleum (Americas), Inc.
Black Hills Energy
Boardwalk Pipeline Partners, LP
Boart Longyear
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
BreitBurn Management Company
Bridwell Oil Company
Brigham Exploration Company
Brookfield Renewable Power
Buckeye Partners, L.P.
Burnett Oil Co., Inc.
Calfrac Well Services Corporation
California ISO
Cameron International
Cameron International – Drilling and Production Systems
Cameron International – Process and Compression Systems
Cameron International – Valves & Measurement
Caterpillar, Inc. – Global Petroleum
CEDA International Inc.
CenterPoint Energy
Central Hudson Gas & Electric Corp.
CHS Inc.
CHS Inc. – Energy, Energy Marketing
CHS Inc. – Energy, Refineries
Cimarex Energy Co.
Cinco Natural Resources Corporation
Citation Oil & Gas Corp.
CITGO Petroleum Corporation
Colonial Pipeline Company
Consolidated Edison
Copano Energy
Copano Energy – Scissortail Energy, LLC
Core Laboratories
CPS Energy
Crosstex Energy Services
CVR Energy, Inc.
CVR Energy, Inc. – Coffeyville Terminal, LLC
CVR Energy, Inc. – Crude Transportation, LLC
CVR Energy, Inc. – Nitrogen Fertilizers, LLC
CVR Energy, Inc. – Refining & Marketing, LLC
Davis Petroleum Corp.
DCP Midstream, LLC
Denbury Resources, Inc.
Det Norske Veritas US
Devon Energy
Diamond Offshore Drilling, Inc.
Direct Energy Marketing Ltd. US
DM PETEROLUEM OPERATIONS
Dominion Resources, Inc.
Dominion Resources, Inc. – Dominion Energy
Dominion Resources, Inc. – Dominion Generation
Dominion Resources, Inc. – Dominion Virginia Power
Edison Mission Energy
El Paso Corporation
El Paso Corporation – Exploration and Production
El Paso Corporation – Pipeline Group
ElectriCities of North Carolina, Inc.
Enbridge Liquids Pipelines
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
EnerVest Management Partners, Ltd. – EV Energy Partners, LP
EnerVest, Ltd.
Eni US Operating Company, Inc.
ENSCO International, Inc.
ENSCO International, Inc. – Deepwater Business Unit
ENSCO International, Inc. – North & South America Business Unit
Ensign United States Drilling, Inc.
Ensign United States Drilling, Inc. – California
Entegra Power Services, LLC
Entergy
Entergy – Non-Regulated
Entergy – Regulated
EOG Resources, Inc.
Equal Energy US Inc.
ERIN Engineering and Research, 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
Explorer Pipeline Company
Fasken Oil and Ranch, Ltd.
Finley Resources Inc.
First Solar
Forest Oil Corporation
General Electric Energy
Genesis Energy, LLC
Global Industries
Great River Energy
Halliburton Company
Helix Energy Solutions Group
Helmerich & Payne, Inc.
Hercules Offshore, Inc.
Hess Corporation
HighMount Exploration & Production LLC
Hilcorp Energy Company
Hilcorp Energy Company – Harvest Pipeline Company

Holly Corporation
Holly Corporation – Asphalt Company
Holly Corporation – Holly Refining and Marketing Tulsa LLC
Holly Corporation – Logistic Services
Holly Corporation – Navajo Refining Company
Holly Corporation – Refining and Marketing Woods Cross
Hunt Consolidated Inc. – Hunt Oil Company
Husky Energy Inc.
Information Handling Services (IHS)
ION Geophysical Corporation
Jacksonville Electric Authority
J-W Operating Company
J-W Operating Company – J-W Gathering Company
J-W Operating Company – J-W Manufacturing 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.
Legacy Reserves LP
LG&E and KU Energy LLC
LINN Energy, LLC
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
MCX Exploration (USA), Ltd.
MDU Resources Group, Inc.
MDU Resources Group, Inc. – WBI Holdings, Inc.
Mestena Operating, L.L.C.
Mitsui E&P USA LLC
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
Nexen Petroleum USA, Inc.
Nippon Oil Exploration USA Ltd.
NiSource Inc.
NiSource Inc. – Columbia Gas of Kentucky
NiSource Inc. – Columbia Gas of Massachusetts
NiSource Inc. – Columbia Gas of Ohio
NiSource Inc. – Columbia Gas of Pennsylvania
NiSource Inc. – Columbia Gas of Virginia
NiSource Inc. – Kokomo Gas And Fuel Company
NiSource Inc. – NiSource Gas Transmission & Storage
NiSource Inc. – Northern Indiana Fuel & Light
NiSource Inc. – Northern Indiana Public Service Company
NiSource Inc. – Transmission Corporation
Noble Corporation
Noble Corporation – Noble Drilling Services, Inc.
Noble Energy, Inc.
Northwest Natural Gas
NSTAR Electric & Gas
Oceaneering International, Inc.
Oceaneering International, Inc. – Americas
Oceaneering International, Inc. – Inspection
Oceaneering International, Inc. – Oceaneering Intervention Engineering
Oceaneering International, Inc. – Umbilicals
OGE Energy Corporation
ONEOK, Inc.
ONEOK, Inc. – Kansas Gas Services Division
ONEOK, Inc. – Oklahoma Natural Gas Division
ONEOK, Inc. – ONEOK Energy Services Company
ONEOK, Inc. – ONEOK Partners
ONEOK, Inc. – Texas Gas Services Division
PacifiCorp
Parallel Petroleum LLC
Parker Drilling Company
Pason Systems USA Corp.
Pason Systems USA Corp. – Auxsol Inc.
Pason Systems USA Corp. – Pason Offshore
PDC Energy
Petrohawk Energy Corporation
Piedmont Natural Gas Company, Inc.
Pioneer Natural Resources
PJM Interconnection
Plains All American Pipeline, L.P.
Plains All American Pipeline, L.P. – PAA Natural Gas Storage, L.P.
Plains Exploration & Production Company
Precision Drilling Corporation
Puget Sound Energy
QEP Resources, Inc
Quicksilver Resources Inc.
R. Lacy, Inc.
Range Resources Corp.
Regency Energy Partners LP
Regency Energy Partners LP – Contract Compression Segment
Repsol Services Company
RKI Exploration & Production, LLC
Rosewood Resources, Inc.
Rowan Companies, Inc.
Safety-Kleen Systems, Inc.
SCANA Corporation
SCANA Corporation – Carolina Gas Transmission Corporation
SCANA Corporation – PSNC Energy
SCANA Corporation – SC Electric & Gas
SCANA Corporation – SEMI (SCANA Energy Marketing, Inc.)
Schlumberger Limited – Schlumberger Oilfield Services
Science Applications International Corporation (SAIC)
Seadrill Americas Inc.
SemGroup Corporation
SemGroup Corporation – SemCrude
SemGroup Corporation – SemGas
SemGroup Corporation – SemStream
Seneca Resources Corporation
Seneca Resources Corporation – East
Seneca Resources Corporation – West
SK E&P Company
Southern Company
Southern Company – Gulf Power Company
Southern Company – SouthernLINC
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
Spectra Energy Corp.
Sprague Energy Corp.
Stantec Inc.
Statoil
Superior Energy Services, Inc.
Superior Energy Services, Inc. – Completion Services
Superior Energy Services, Inc. – Well Solutions
Superior Energy Services, Inc.- HB Rentals
Superior Pipeline Company
Talisman Energy Inc. US
Tellus Operating Group, LLC
Tesco Corporation
TGS-NOPEC Geophysical Company
The Williams Companies, Inc.
THUMS Long Beach Company
TOTAL E&P USA, Inc.
TransCanada Corporation
TransCanada Corporation – Energy Group
Transocean, Inc.
Unit Corporation
Unit Drilling Company
Unit Petroleum Company
United Water
Venoco, Inc.
Verado Energy, Inc.
Weatherford – US Region
WGL Holdings, Inc. – Washington Gas
Whiting Petroleum Corporation
Xcel Energy Inc.

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Stockholder Information

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 2013 was 688,180 shares.

Common Stock Prices

	High	Low	Close
2013			
First Quarter	$25.00	$21.50	$24.99
Second Quarter	27.14	23.37	25.91
Third Quarter	30.21	25.94	27.97
Fourth Quarter	30.97	27.53	30.55
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

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.

2014 Key Dividend Dates

	Ex-Dividend Date	Record Date	Payment Date
First Quarter	March 11	March 13	April 1
Second Quarter	June 10	June 12	July 1
Third Quarter	September 9	September 11	October 1
Fourth Quarter	December 9	December 11	January 1, 2015

Key dividend dates are subject to the discretion of the Board of Directors.

Annual Meeting

Tuesday, April 22, 2014
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 Registered Public Accounting Firm

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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