e-FILING REPORT COVER SHEET

COMPANY NAME: Cascade Natural Gas Corporation

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ☒ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☒ Yes, report docket number: RG-33

Report is required by: ☒ OAR 860-027-0070
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

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

List Key Words for this report. We use these to improve search results.

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

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

Print

THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 2 Approved
OMB No.1902-0028
(Expires 12/31/2020)

Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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** 2018/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 167 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	Year/Period of Report
Cascade Natural Gas Corporation	End of 2018/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	06 Title of Contact Person
Kevin Conwell	Manager, 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	This Report Is:	10 Date of Report (Mo, Da, Yr)
509-734-4524	(1) [X] An Original (2) [ ] A Resubmission	12/31/2018

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	12 Title
Kevin Conwell	Manager, Accounting & Finance
13 Signature Kevin Conwell	14 Date Signed 04/15/2019

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	12/31/2018	End of 2018/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."

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.

Kevin Conwell
Manager, 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	12/31/2018	End of 2018/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	12/31/2018	End of 2018/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					
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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	12/31/2018	End of 2018/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	MDU Resources Group, Inc.				
13	PO Box 5650				
14	Bismarck, ND 58506-5650				
15					
16					
17					
18					
19					
20					

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 union employees increased 3.00% in June 2018.
9. None
10. None
11. WA Rate Agreement (Docket UG-170929 Order 06, Entered 07/20/2018, Rates Effective 08/01/2019)

Revenue Class	Change	%Change	Number of Customers	
Residential	($3,408,301.00)	-7.50%	183,772	
Commercial	($1,813,411.00)	-7.50%	25,601	
Industrial	($148,146.00)	-7.50%	440	
Large Volume	($115,322.00)	-7.50%	90	
Interruptible	($16,053.00)		-7.50%	10
Transportation	($1,084,051.00)	-7.50%	188	
Total	($6,585,284.00)	-7.50%	210,101	

12. Changes to Corporate Officers:
Scott Madison became Executive Vice President - Business Development and Gas Supply

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	12/31/2018	2018/Q4

Important Changes During the Quarter/Year

Patrick Darras became Vice President - Engineering and Operations Services
Hart Gilchrist became Vice President - Safety, Process Improvement and Operations Systems
Eric Martuscelli became Vice President - Field Operations

None

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	12/31/2018	End of 2018/Q4

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	1,077,226,744	997,637,482
3	Construction Work in Progress (107)	200-201	12,854,207	8,458,804
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	1,090,080,951	1,006,096,286
5	(Less) Accum. Provision for Depr., Amort., Depl. (108, 111, 115)		490,730,756	477,141,386
6	Net Utility Plant (Total of line 4 less 5)		599,350,195	528,954,900
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)		599,350,195	528,954,900
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	12,371,315	11,692,638
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)		12,573,345	11,894,668
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)		3,203,159	2,727,130
33	Special Deposits (132-134)		0	0
34	Working Funds (135)		1,150	1,550
35	Temporary Cash Investments (136)	222-223	0	0
36	Notes Receivable (141)		0	0
37	Customer Accounts Receivable (142)		10,776,951	12,549,415
38	Other Accounts Receivable (143)		13,165,937	2,255,787
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		460,922	471,321
40	Notes Receivable from Associated Companies (145)		0	0
41	Accounts Receivable from Associated Companies (146)		129,531	0
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)		5,694,283	8,026,535
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	396,659	587,529
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220	1,940,549	2,230,775
54	Prepayments (165)	230	4,497,288	3,305,688
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)		25,164,950	32,360,206
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)		64,509,535	63,573,294
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)		1,624,524	1,646,972
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	56,168,845	47,795,198
70	Preliminary Survey and Investigation Charges (Electric)(183)		0	0
71	Preliminary Survey and Investigation Charges (Gas)(183.1 and 183.2)		0	367
72	Clearing Accounts (184)		59,785	39,416
73	Temporary Facilities (185)		0	0
74	Miscellaneous Deferred Debits (186)	233	79,056,464	70,740,286
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)		744,300	785,271
78	Accumulated Deferred Income Taxes (190)	234-235	17,102,003	16,343,135
79	Unrecovered Purchased Gas Costs (191)		0	0
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		154,755,921	137,350,645
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		831,188,996	741,773,507

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	12/31/2018	End of 2018/Q4

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	222,117,553	192,553,017
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	34,416,894	30,688,673
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	2,318,457	1,270,661
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)		258,853,904	224,513,351
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	268,211,000	214,471,000
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)		268,211,000	214,471,000
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)		13,232,381	14,261,343
29	Accumulated Provision for Pensions and Benefits (228.3)		5,811,780	8,407,713
30	Accumulated Miscellaneous Operating Provisions (228.4)		24,135	48,270
31	Accumulated Provision for Rate Refunds (229)		1,558,020	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)		66,788,046	61,208,026
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		87,414,362	83,925,352
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-Term Debt		0	0
38	Notes Payable (231)		0	17,300,000
39	Accounts Payable (232)		66,439,118	29,768,720
40	Notes Payable to Associated Companies (233)		0	0
41	Accounts Payable to Associated Companies (234)		2,007,577	1,690,801
42	Customer Deposits (235)		893,105	904,903
43	Taxes Accrued (236)	262-263	7,285,166	8,002,294
44	Interest Accrued (237)		3,155,341	3,121,957
45	Dividends Declared (238)		2,960,000	3,300,000
46	Matured Long-Term Debt (239)		0	0
47	Matured Interest (240)		0	0
48	Tax Collections Payable (241)		1,309	0
49	Miscellaneous Current and Accrued Liabilities (242)	268	8,958,797	8,843,156
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)		91,700,413	72,931,831
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)		4,315,901	4,487,518
58	Accumulated Deferred Investment Tax Credits (255)		243,929	286,113
59	Deferred Gains from Disposition of Utility Plant (256)		0	0
60	Other Deferred Credits (253)	269	(31,014,246)	(980,392)
61	Other Regulatory Liabilities (254)	278	62,967,793	64,721,420
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)		53,594,339	52,078,937
65	Accumulated Deferred Income Taxes - Other (283)		34,901,601	25,378,377
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		125,009,317	145,971,973
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		831,188,996	741,813,507

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	286,825,673	290,448,860	0	0
3	Operating Expenses					
4	Operation Expenses (401)	317-325	192,939,765	194,391,007	0	0
5	Maintenance Expenses (402)	317-325	8,005,146	7,645,195	0	0
6	Depreciation Expense (403)	336-338	26,303,413	24,014,068	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	3,486,360	3,032,663	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	0	0	0
13	(Less) Regulatory Credits (407.4)		0	0	0	0
14	Taxes Other than Income Taxes (408.1)	262-263	28,430,305	29,055,993	0	0
15	Income Taxes-Federal (409.1)	262-263	(5,420,218)	(2,234,179)	0	0
16	Income Taxes-Other (409.1)	262-263	(461,582)	(129,101)	0	0
17	Provision of Deferred Income Taxes (410.1)	234-235	17,131,551	11,134,553	0	0
18	(Less) Provision for Deferred Income Taxes-Credit (411.1)	234-235	10,752,441	0	0	0
19	Investment Tax Credit Adjustment-Net (411.4)		(42,184)	(38,175)	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)		259,620,115	266,872,024	0	0
26	Net Utility Operating Income (Total of lines 2 less 25) (Carry forward to page 116, line 27)		27,205,558	23,576,836	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	286,825,673	290,448,860	0	0
3						
4	0	0	192,939,765	194,391,007	0	0
5	0	0	8,005,146	7,645,195	0	0
6	0	0	26,303,413	24,014,068	0	0
7	0	0	0	0	0	0
8	0	0	3,486,360	3,032,663	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	0	0	0
13	0	0	0	0	0	0
14	0	0	28,430,305	29,055,993	0	0
15	0	0	(5,420,218)	(2,234,179)	0	0
16	0	0	(461,582)	(129,101)	0	0
17	0	0	17,131,551	11,134,553	0	0
18	0	0	10,752,441	0	0	0
19	0	0	(42,184)	(38,175)	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	259,620,115	266,872,024	0	0
26	0	0	27,205,558	23,576,836	0	0

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report End of 2018/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)		27,205,558	23,576,836	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)		8,687	10,781	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)		513,668	568,811	0	0
38	Allowance for Other Funds Used During Construction (419.1)		47,519	177,923	0	0
39	Miscellaneous Nonoperating Income (421)		25,876	28,939	0	0
40	Gain on Disposition of Property (421.1)		0	0	0	0
41	TOTAL Other Income (Total of lines 31 thru 40)		595,750	786,454	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	147,336	299,157	0	0
46	Life Insurance (426.2)		452,957	(291,752)	0	0
47	Penalties (426.3)		51	0	0	0
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		165,577	128,933	0	0
49	Other Deductions (426.5)		615,677	1,097	0	0
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)	340	1,381,598	137,435	0	0
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other than Income Taxes (408.2)	262-263	1,145	1,106	0	0
53	Income Taxes-Federal (409.2)	262-263	(244,676)	(1,365)	0	0
54	Income Taxes-Other (409.2)	262-263	(27,118)	1,079	0	0
55	Provision for Deferred Income Taxes (410.2)	234-235	152,659	0	0	0
56	(Less) Provision for Deferred Income Taxes-Credit (411.2)	234-235	114,241	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)		(232,231)	820	0	0
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(553,617)	648,199	0	0
61	INTEREST CHARGES					
62	Interest on Long-Term Debt (427)		11,687,433	11,403,441	0	0
63	Amortization of Debt Disc. and Expense (428)	258-259	200,173	454,448	0	0
64	Amortization of Loss on Reacquired Debt (428.1)		40,971	40,971	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	359,840	505,177	0	0
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)		291,153	253,406	0	0
70	Net Interest Charges (Total of lines 62 thru 69)		11,997,264	12,150,631	0	0
71	Income Before Extraordinary Items (Total of lines 27,60 and 70)		14,654,677	12,074,404	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)		14,654,677	12,074,404	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, 2018

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	-	-	27,205,558	23,576,836	-	-
28	[redacted]					
29						
30						
31	-	-	-	-	-	-
32	-	-	-	-	-	-
33	-	-	8,687	10,781	-	-
34	-	-	-	-	-	-
35	-	-	-	-	-	-
36	-	-	-	-	-	-
37	-	-	513,668	568,811	-	-
38	-	-	47,519	177,923	-	-
39	-	-	25,876	28,939	-	-
40	-	-	-	-	-	-
41	-	-	595,750	786,454	-	-
42	[redacted]					
43			-	-		
44			-	-		
45			147,336	299,157		
46			452,957	(291,752)		
47			51	-		
48			165,577	128,933		
49	-	-	615,677	1,097	-	-
50	-	-	1,381,598	137,435	-	-
51	[redacted]					
52			1,145	1,106		
53	-	-	(244,676)	(1,365)	-	-
54	-	-	(27,118)	1,079	-	-
55	-	-	152,659	-	-	-
56	-	-	(114,241)	-	-	-
57	-	-	-	-	-	-
58	-	-	-		-	-
59	-	-	(232,231)	820	-	-
60	-	-	(553,617)	648,199	-	-
61	[redacted]					
62	-	-	11,687,433	11,403,441	-	-
63	-	-	200,173	454,448	-	-
64	-	-	40,971	40,971	-	-
65	-	-	-	-	-	-
66	-	-	-	-	-	-
67	-	-	-	-	-	-
68	-	-	359,840	505,177	-	-
69	-	-	(291,153)	(253,406)	-	-
70	-	-	11,997,264	12,150,631	-	-
71	-	-	14,654,677	12,074,404	-	-
72	[redacted]					
73	-	-	-	-	-	-
74	-	-	-	-	-	-
75	-	-	-	-	-	-
76	-	-	-	-	-	-
77	-	-	-	-	-	-
78	-	-	14,654,677	12,074,404	-	-

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	12/31/2018	End of 2018/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		1,270,661		
4	Total (lines 2 and 3)		1,270,661		
5	Balance of Account 219 at End of Preceding Quarter/Year		1,270,661		
6	Balance of Account 219 at Beginning of Current Year		1,270,661		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		1,047,796		
9	Total (lines 7 and 8)		1,047,796		
10	Balance of Account 219 at End of Current Quarter/Year		2,318,457		

Statement of Accumulated Comprehensive Income and Hedging Activities(continued)

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to specify 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			1,270,661		
4			1,270,661	12,074,404	13,345,065
5			1,270,661		
6			1,270,661		
7					
8			1,047,796		
9			1,047,796	14,654,677	15,702,473
10			2,318,457		

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		30,688,673	31,852,511
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)		(273,680)	
5	TOTAL Debits to Retained Earnings (Account 439) (footnote details)			
6	Balance Transferred from Income (Acct 433 less Acct 418.1)		14,654,677	12,074,404
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)		10,652,776	13,238,242
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)		34,416,894	30,688,673
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		34,416,894	30,688,673
21	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)			
	Report only on an Annual Basis no Quarterly			
22	Balance-Beginning of Year (Debit or Credit)			
23	Equity in Earnings for Year (Credit) (Account 418.1)			
24	(Less) Dividends Received (Debit)			
25	Other Changes (Explain)			
26	Balance-End of Year			

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2018	End of 2018/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)	14,654,677	12,074,404
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	29,789,773	27,046,732
5	Amortization of (Specify) (footnote details): Gas cost changes	(31,058,841)	(15,731,419)
6	Deferred Income Taxes (Net)	6,417,528	11,134,553
7	Investment Tax Credit Adjustments (Net)	(42,184)	(38,175)
8	Net (Increase) Decrease in Receivables	(4,695,510)	1,232,417
9	Net (Increase) Decrease in Inventory	481,096	(986,484)
10	Net (Increase) Decrease in Allowances Inventory		
11	Net Increase (Decrease) in Payables and Accrued Expenses	26,100,059	(3,573,373)
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	(9,240,144)	4,483,143
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of Lines 2 thru 16)	32,406,454	35,641,798
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(86,201,261)	(71,112,784)
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	47,519	177,923
27	Other (footnote details): Net increase in customer advances for construction	(171,617)	416,891
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(86,420,397)	(70,873,816)
29			
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)	67,301	(376,020)
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	(672,266)	(22,527)
48	Net Cash Provided by (Used in) Investing Activities		
49	(Total of lines 28 thru 47)	(87,025,362)	(71,272,363)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)	36,550,000	17,063,033
54	Preferred Stock		
55	Common Stock	30,000,000	32,000,000
56	Other (footnote details):	(37,702)	(14,266)
57	Net Increase in Short-term Debt (c)		
58	Other (footnote details):		
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	66,512,298	49,048,767
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)	(70,000)	(40,000)
63	Preferred Stock		
64	Common Stock	(397,761)	(131,385)
65	Other (footnote details):		
66	Net Decrease in Short-Term Debt (c)		
67			
68	Dividends on Preferred Stock		
69	Dividends on Common Stock	(10,950,000)	(14,060,000)
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of lines 59 thru 69)	55,094,537	34,817,382
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of line 18, 49 and 71)	475,629	(813,183)
75			
76	Cash and Cash Equivalents at Beginning of Period	2,728,680	3,541,863
77			
78	Cash and Cash Equivalents at End of Period	3,204,309	2,728,680

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

Definitions

The following abbreviations and acronyms used in these Financial Statements and Notes are defined below:

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ARO	Asset retirement obligation
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
Cascade	Cascade Natural Gas Corporation, a direct wholly owned subsidiary of PCEH
Company	MDU Energy Capital, LLC, a direct wholly owned subsidiary of MDU
EBITDA	Earnings before interest, taxes, depreciation and amortization
EIN	Employer Identification Number
EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
Intermountain	Intermountain Gas Company, a direct wholly owned subsidiary of PIEH
IPUC	Idaho Public Utilities Commission
MAOP	Maximum allowable operating pressure
MDU	MDU Resources Group, Inc.
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of MDU
OPUC	Oregon Public Utility Commission
PCEH	Prairie Cascade Energy Holdings, LLC, a direct wholly owned subsidiary of the Company
PIEH	Prairie Intermountain Energy Holdings, LLC, a direct wholly owned subsidiary of the Company
PRP	Potentially Responsible Party
ROD	Record of Decision
RP	Rehabilitation plan
SEC	United States Securities and Exchange Commission
TCJA	Tax Cuts and Jobs Act
Washington DOE	Washington State Department of Ecology
WUTC	Washington Utilities and Transportation Commission

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2018 and 2017

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 658,000 residential, commercial and industrial customers in 170 communities. 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 regulation by 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 operating expenses.

Management has also evaluated the impact of events occurring after December 31, 2018, up to the date of the issuance of these consolidated financial statements on March 28, 2019, that would require recognition or disclosure in the financial statements.

On December 22, 2017, President Trump signed into law the TCJA which includes lower corporate tax rates, repealing the domestic production deduction, disallowance of immediate expensing for regulated utility property and modifying or repealing many other business deductions and credits. The reduction in the corporate tax rate was effective on January 1, 2018. The effects of the change in tax laws or rates must be accounted for in the period of enactment, which resulted in the Company making reasonable estimates of the impact of the reduction in corporate tax rate on the Company's net deferred tax liabilities during the fourth quarter of 2017. The SEC issued rules that allowed for a measurement period of up to one year after the enactment date of the TCJA to finalize the recording of the related tax impacts. At December 31, 2018, the Company finalized the estimates from the fourth quarter of 2017 and no material adjustments were recorded to income from continuing operations during the twelve months ended December 31, 2018.

Due to the enactment of the TCJA, the regulated jurisdictions in which the Company's regulated businesses provide service requested the Company furnish plans for the effect of the reduced corporate tax rate, which impacted the Company's rates to customers. Therefore, the Company reserved for such impacts as an offset to revenue or is passing back to customers through lower rates in certain jurisdictions. For more information on the details and statuses of the open requests, see Note 10.

Effective January 1, 2018, the Company adopted the requirements of the accounting standard update on revenue from contracts with customers following the modified retrospective method, as further discussed in this note. As such, results for reporting periods beginning January 1, 2018, are presented under the new guidance, while prior period amounts are not adjusted and continue to be reported in accordance with the historic accounting for revenue recognition. Based on the Company's analysis, the Company did not identify a significant change in the timing of revenue recognition under the new guidance as compared to the historic accounting for revenue recognition.

Certain prior year amounts have been reclassified to conform to the current year presentation in the consolidated financial statements related to the retrospective adoption of the accounting standard update to improve the presentation of net periodic pension and net periodic postretirement benefit costs, which was effective on January 1, 2018. The components of net periodic pension and postretirement costs, other than service costs, were reclassified from operating expenses to other income on the Consolidated Statements of Income, as further discussed in this note.

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 $602,000 and $685,000 as of December 31, 2018 and 2017, 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 at December 31, 2018 and 2017 was $739,000 and $740,000, respectively.

Natural gas in storage
Natural gas in storage is carried at cost using the first-in, first-out method at Cascade and using the lower of cost or net realizable value method at Intermountain. Natural gas in storage is expected to be used within one year and the value included in inventories was $7.6 million and $8.6 million at December 31, 2018 and 2017, 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 9.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. The amount of AFUDC capitalized for the years ended December 31 was as follows:

	2018	2017
	(In thousands)	
AFUDC - borrowed	**$ 660**	$ 336
AFUDC - equity	**$ 48**	$ 178

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 deferred credits and other liabilities-other.

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

	2018	2017	Weighted Average Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Distribution plant	**$ 1,433,568**	$ 1,325,256	48
Transmission plant	**96,425**	96,320	52
Storage plant	**28,818**	25,988	23
General plant	**125,820**	113,138	17
Other plant	**90,409**	88,421	11
Non-depreciable plant	**9,000**	9,000	-
Construction in progress	**16,906**	12,825	-
Less: Accumulated depreciation and amortization	**614,226**	588,788	
Net property, plant and equipment	**$ 1,186,720**	$ 1,082,160	

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 2018 and 2017. 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, 2018 and 2017, there were no impairment losses recorded. At December 31, 2018, 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, risk adjusted 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 risk adjusted cost of capital. The risk adjusted cost of capital of 5.0 percent, and a long-term growth rate projection of 3.5 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2018. Under the market approach, the Company estimates fair value using multiples derived from 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.

Revenue recognition

Revenue is recognized when a performance obligation is satisfied by transferring control over a product or service to a customer. Revenue is measured based on consideration specified in a contract with a customer, and excludes any sales incentives and amounts collected on behalf of third parties. The Company is considered an agent for certain taxes collected from customers. As such, the Company presents revenues net of these taxes at the time of sale to be remitted to governmental authorities, including sales and use taxes.

The Company generates revenue from the sales of natural gas products and services, which includes retail and transportation services. The Company establishes a customer's retail or transportation service account based on the customer's application/contract for service, which indicates approval of a contract for service. The contract identifies an obligation to provide service in exchange for delivering or standing ready to deliver the identified commodity; and the customer is obligated to pay for the service as provided in the applicable tariff. The product sales are based on a fixed rate that includes a base and per-unit rate, which are included in approved tariffs as determined by state or federal regulatory agencies. The quantity of the commodity consumed or transported determines the total per-unit revenue. The service provided, along with the product consumed or transported, are a single performance obligation because both are required in combination to successfully transfer the contracted product or service to the customer. Revenues are recognized over time as customers receive and consume the products and services. The method of measuring progress toward the completion of the single performance obligation is on a per-unit output method basis, with revenue recognized based on the direct measurement of the value to the customer of the goods or services transferred to date. For contracts governed by the Company's utility tariffs, amounts are billed monthly with the amount due between 15 and 22 days of receipt of the invoice depending on the applicable state's tariff. For other contracts not governed by tariff, payment terms are net 30 days. At this time, the Company has no material obligations for returns, refunds or other similar obligations.

The Company recognizes all other revenues when services are rendered or goods are delivered.

Asset retirement obligations
The Company performed detailed assessments of ARO's for the retirement 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. 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 which are filed annually. Natural gas costs refundable through rate adjustments were $26.2 million and $27.8 million at December 31, 2018 and 2017, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $41.5 and $11.6 million at December 31, 2018 and 2017, respectively, which is included in prepayments and other current assets.

Stock-based compensation
The Company determines compensation expense for stock-based awards based on the estimated fair values at the grant date and recognizes the related compensation expense over the vesting period. The Company uses the straight-line amortization method to recognize compensation expense related to restricted stock, which only has a service condition. This method recognizes stock compensation expense on a straight-line basis

over the requisite service period for the entire award. The Company recognizes compensation expense related to performance awards that vest based on performance metrics and service conditions on a straight-line basis over the service period. Inception-to-date expense is adjusted based upon the determination of the potential achievement of the performance target at each reporting date. The Company recognizes compensation expense related to performance awards with market-based performance metrics on a straight-line basis over the requisite service period.

The Company records the compensation expense for performance share awards using an estimated forfeiture rate. The estimated forfeiture rate is calculated based on an average of actual historical forfeitures. The Company also performs an analysis of any known factors at the time of the calculation to identify any necessary adjustments to the average historical forfeiture rate. At the time actual forfeitures become more than estimated forfeitures, the Company records compensation expense using actual forfeitures.

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 by using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. 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-other. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in deferred credits and other liabilities. 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 ratemaking 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.

The Company records uncertain tax positions in accordance with accounting guidance on accounting for income taxes on the basis of a two-step process in which (1) the Company determines whether it is more-likely-than-not that the tax position will be sustained on the basis of the technical merits of the position and (2) for those tax positions that meet the more-likely-than-not recognition threshold, the Company recognizes the largest amount of the tax benefit that is more than 50 percent likely to be realized upon ultimate settlement with the related tax authority. Tax positions that do not meet the more-likely-than-not criteria are reflected as a tax liability. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

Use of estimates

The preparation of financial statements in conformity with GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of long-lived assets and goodwill; fair values of acquired assets and liabilities under the acquisition method of accounting; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; and the value of stock-based compensation. 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.

New accounting standards

Recently adopted accounting standards

ASU 2014-09 - Revenue from Contracts with Customers In May 2014, the FASB issued guidance on accounting for revenue from contracts with customers. The guidance provides for a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry specific guidance. In August 2015, the FASB issued guidance deferring the effective date of the revenue guidance and allowing entities to early adopt. With this decision, the guidance was early adopted by the Company on January 1, 2018. Entities had the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified retrospective approach, an entity recognizes the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption.

The Company adopted the guidance on January 1, 2018, using the modified retrospective approach. The Company elected the practical expedient to not disclose the aggregate amount of the transaction price allocated to the performance obligations that are unsatisfied (or partially unsatisfied) as of the end of the reporting period, along with an explanation of when such revenue would be expected to be recognized. This practical expedient was used since the performance obligations are part of contracts with an original duration of one year or less. The Company also elected the practical expedient to recognize the incremental costs of obtaining a contract as an expense when incurred if the amortization period of the asset that the Company otherwise would have recognized is one year or less. Upon completion of the Company's evaluation of contracts and methods of revenue recognition under the previous accounting guidance, the Company did not identify any material cumulative effect adjustments to be made to retained earnings. In addition, the Company has expanded revenue disclosures, both quantitatively and qualitatively, related to the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. The Company reviewed its revenue streams to evaluate the impact of this guidance and did not identify a significant change in the timing of revenue recognition, results of operations, financial position or cash flows. The Company reviewed its internal controls related to revenue recognition and disclosures and concluded that the guidance impacted certain business processes and controls. As such, the Company developed modifications to its internal controls for certain topics under the guidance as they apply to the Company and such modifications were not deemed to be significant. Results for reporting periods beginning after December 31, 2017, are presented under the new guidance, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting for revenue recognition.

Under the modified retrospective approach, the guidance was applied only to contracts that were not completed as of January 1, 2018. For the twelve months ended December 31, 2018, there were no material impacts to the financial statements as a result of applying the guidance.

ASU 2016-15 - Classification of Certain Cash Receipts and Cash Payments In August 2016, the FASB issued guidance to clarify the classification of certain cash receipts and payments in the statement of cash flows. The guidance is intended to standardize the presentation and classification of certain transactions, including cash payments for debt prepayment or extinguishment, proceeds from insurance claim settlements and distributions from equity method investments. In addition, the guidance clarifies how to classify transactions that have characteristics of more than one class of cash flows. The Company early adopted the guidance on January 1, 2018, on a prospective basis. The guidance did not have a material effect on the Company's statement of cash flows.

ASU 2017-01 - Clarifying the Definition of a Business In January 2017, the FASB issued guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The guidance also affects other aspects of accounting, such as determining reporting units for goodwill testing and whether an entity has acquired or sold a business. The Company early adopted the guidance on January 1, 2018, on a prospective basis. The guidance did not have a material effect on the Company's results of operations, financial position, cash flows or disclosures.

ASU 2017-07 - Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost In March 2017, the FASB issued guidance to improve the presentation of net periodic pension and net periodic postretirement benefit costs. The guidance required the service cost component to be presented in the income statement in the same line item or items as other compensation costs arising from services performed during the period. Other components of net periodic benefit cost shall be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The guidance also allows only the service cost component to be capitalized.

The Company early adopted the guidance on January 1, 2018, on a retrospective basis. The guidance required the reclassification of all components of net periodic benefit costs, except for the service cost component, from operating expenses to other income on the Consolidated Statements of Income with no impact to earnings. As a result of the retrospective application of this change in accounting guidance, the Company reclassified $655,000 from operation and maintenance expense to other income on the Consolidated Statements of Income for the year ended December 31, 2017. The Company also reclassified unrealized gains on investments used to satisfy obligations under the defined benefit plans of $1.7 million for the year ended December 31, 2017, which were included in operation and maintenance expense, to other income on the Consolidated Statements of Income. The guidance did not have a material effect on the Company's results of operations, cash flows or disclosures.

ASU 2018-02 - Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income In February 2018, the FASB issued guidance that allows an entity to reclassify the stranded tax effects resulting from the newly enacted federal corporate income tax rate from accumulated other comprehensive income (loss) to retained earnings. The guidance is effective for the Company on January 1, 2019, with early adoption permitted. The guidance can be applied using one of two methods. One method is to record the reclassification of the stranded income taxes at the beginning of the period of adoption. The other method is to apply the guidance retrospectively to each period in which the income tax effects of the TCJA are recognized in accumulated other comprehensive income (loss). The Company early adopted the guidance on January 1, 2018, and elected to reclassify the stranded income taxes at the beginning of the period. During 2018, the Company reclassified $246,000 of stranded tax expense from accumulated other comprehensive loss to retained earnings. The guidance did not have a material effect on the Company's results of operations, cash flows or disclosures.

Recently issued accounting standards not yet adopted

ASU 2016-02 - Leases In February 2016, the FASB issued guidance regarding leases. The guidance requires lessees to recognize a lease liability and a right-of-use asset on the balance sheet for operating and financing leases. The guidance remains largely the same for lessors, although some changes were made to better align lessor accounting with the new lessee accounting and to align with the revenue recognition standard. The guidance also requires additional disclosures, both quantitative and qualitative, related to operating and finance leases for the lessee and sales-type, direct financing and operating leases for the lessor. The Company early adopted the standard on January 1, 2019.

In July 2018, the FASB issued ASU 2018-11 - Leases: Targeted Improvements, an accounting standard update to ASU 2016-02. This ASU provides an entity the option to adopt the guidance using one of two modified retrospective approaches. An entity can adopt the guidance using the modified retrospective transition approach beginning in the earliest year presented in the financial statements. This method of adoption would require the restatement of prior periods reported and the presentation of lease disclosures under the new guidance for all periods reported. The additional transition method of adoption introduced by ASU 2018-11, allows entities the option to apply the guidance on the date of adoption by recognizing a cumulative effect adjustment to retained earnings during the period of adoption and does not require prior comparative periods to be restated. The Company early adopted the standard on January 1, 2019, utilizing the practical expedient that allows the Company to not reassess whether an expired or existing contract contains a lease, the classification of leases or initial direct costs, as well as the additional transition method of adoption applied on the date of adoption. The Company also adopted a short-term leasing policy as the lessee where leases with a term of 12 months or less will not be included on the Consolidated Balance Sheet.

In January 2018, the FASB issued a practical expedient for land easements under the new lease guidance. The practical expedient permits an entity to elect the option to not evaluate land easements under the new guidance if they existed or expired before the adoption of the new lease guidance and were not previously accounted for as leases under the previous lease guidance. Once an entity adopts the new guidance, the entity should apply the new guidance on a prospective basis to all new or modified land easements. The Company has adopted this practical expedient. The Company will evaluate any new or modified agreements that fall within the scope of the standard. The Company continues to monitor other industry-specific issues as it relates to its regulated businesses but does not expect these issues to have a material impact on the Company's results of operations, financial position or disclosures.

The Company formed a lease implementation team to review and assess existing contracts to identify and evaluate those containing leases. Additionally, the team has implemented new and revised existing software to meet the reporting and disclosure requirements of the standard. The Company also has assessed the impact the standard will have on its processes and internal controls and has identified new and updated existing internal controls and processes to ensure compliance with the new lease standard; such modifications were not deemed to be significant. During the assessment phase, the Company used various surveys, reconciliations and analytic methodologies to ensure the completeness of the lease inventory. The Company determined that most of the current operating leases are subject to the guidance and will be recognized as operating lease liabilities and right-of-use assets on the Consolidated Balance Sheets upon adoption. The Company expects the impact of the lessee guidance to be approximately $500,000 to $1 million of an increase to assets and liabilities on January 1, 2019. In addition, the Company has evaluated the impact the new guidance will have on lease contracts where the Company is the lessor and does not anticipate a significant impact.

ASU 2017-04 - Simplifying the Test for Goodwill Impairment In January 2017, the FASB issued guidance on simplifying the test for goodwill impairment by eliminating Step 2, which required an entity to measure the amount of impairment loss by comparing the implied fair value of reporting unit goodwill with the carrying amount of such goodwill. This guidance requires entities to perform a quantitative impairment test, previously Step 1, to identify both the existence of impairment and the amount of impairment loss by comparing the fair value of a reporting unit to its carrying amount. Entities will continue to have the option of performing a qualitative assessment to determine if the quantitative impairment test is necessary. The guidance also requires additional disclosures if an entity has one or more reporting units with zero or negative carrying amounts of net assets. The guidance will be early adopted for the Company on January 1, 2020, and must be applied on a prospective basis with early adoption permitted. The Company does not expect the guidance to have a material impact on its results of operations, financial position, cash flows and disclosures.

ASU 2018-13 - Changes to the Disclosure Requirements for Fair Value Measurement In August 2018, the FASB issued guidance on modifying the disclosure requirements on fair value measurements as part of the disclosure framework project. The guidance modifies, among other things, the disclosures required for Level 3 fair value measurements, including the range and weighted average of significant unobservable inputs. The guidance removes, among other things, the disclosure requirement to disclose transfers between Levels 1 and 2. The guidance will be effective for the Company on January 1, 2020, including interim periods, with early adoption permitted. Level 3 fair value measurement disclosures should be applied prospectively while all other amendments should be applied retrospectively. The Company is evaluating the effects the adoption of the new guidance will have on its disclosures.

ASU 2018-14 - Changes to the Disclosure Requirements for Defined Benefit Plans In August 2018, the FASB issued guidance on modifying the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans as part of the disclosure framework project. The guidance removes disclosures that are no longer considered cost beneficial, clarifies the specific requirements of disclosures and adds disclosure requirements identified as relevant. The guidance adds, among other things, the requirement to include an explanation for significant gains and losses related to changes in benefit obligations for the period. The guidance removes, among other things, the disclosure requirement to disclose the amount of net periodic benefit costs to be amortized over the next fiscal year from accumulated other comprehensive income (loss) and the effects a one percentage point change in assumed health care cost trend rates will have on certain benefit components. The guidance will be early adopted by the Company on January 1, 2021, and must be applied on a retrospective basis with early adoption permitted. The Company is evaluating the effects the adoption of the new guidance will have on its disclosures.

ASU 2018-15 - Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract In August 2018, the FASB issued guidance on the accounting for implementation costs of a hosting arrangement that is a service contract. The guidance aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract similar to the costs incurred to develop or obtain internal-use software and such capitalized costs to be expensed over the term of the hosting arrangement. Costs incurred during the preliminary and postimplementation stages should continue to be expensed as activities are performed. The capitalized costs are required to be presented on the balance sheet in the same line the prepayment for the fees associated with the hosting arrangement would be presented. In addition, the expense related to the capitalized implementation costs should be presented in the same line on the income statement as the fees associated with the hosting element of the arrangements. The guidance will be effective for the Company on January 1, 2021, including interim periods, and may be applied on a retrospective or a prospective basis with early adoption permitted. The Company early adopted the guidance effective January 1, 2019, on a prospective basis. The adoption of the guidance will not have a material impact on its results of operations, financial position, cash flows and disclosures.

ASU 2018-18 - Clarifying the Interaction between Topic 808 and Topic 606 In November 2018, the FASB issued guidance on whether certain transactions between collaborative arrangement participants should be accounted for within revenue under Topic 606 in order to provide for better comparability among entities. The guidance clarifies which transactions should be accounted for as revenue under Topic 606 and provides unit-of-account guidance in Topic 808 to align with the guidance in Topic 606 regarding distinct goods or services. The guidance also specifies that transactions with a collaborative arrangement not directly related to sales to third parties may not be presented together with revenue recognized under Topic 606. The guidance will be early adopted by the Company on January 1, 2020, including interim periods, and must be applied retrospectively to January 1, 2018, the date in which the Company adopted Topic 606. An entity may apply the guidance to either all contracts or to only contracts that are not completed as of the date of the initial application of Topic 606. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures.

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 postretirement liability adjustments.

The postretirement liability adjustment in other comprehensive loss was $169,000, net of tax of $225,000, for the year ended December 31, 2018.

MDU ENERGY CAPITAL, LLC
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
Years ended December 31, 2018 and 2017

The after-tax changes in the components of accumulated other comprehensive loss were as follows:

Twelve Months Ended December 31, 2018		Postretirement Liability Adjustment		Total Accumulated Other Comprehensive Loss
		(In thousands)		
Balance at December 31, 2017	$	(1,143)	$	(1,143)
Amounts reclassified from accumulated other comprehensive loss		1,220		1,220
Net current-period other comprehensive income		77		77
Reclassification adjustment of prior period tax effects related to TCJA included in accumulated other comprehensive loss		(246)		(246)
Balance at December 31, 2018	**$**	**(169)**	**$**	**(169)**

Twelve Months Ended December 31, 2017		Postretirement Liability Adjustment		Total Accumulated Other Comprehensive Loss
		(In thousands)		
Balance at December 31, 2016	$	---	$	---
Amounts reclassified to accumulated other comprehensive loss from a regulatory asset		(1,143)		(1,143)
Net current-period other comprehensive loss		(1,143)		(1,143)
Balance at December 31, 2017	**$**	**(1,143)**	**$**	**(1,143)**

NOTE 2 – GOODWILL

The carrying amount of goodwill for the years ended December 31, 2018 and 2017 remained unchanged at $340.9 million. 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 *	2018	2017
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(c)	**$ 48,954**	$ 47,953
Manufactured gas plant sites remediation (a)	Largely determined upon filing	**16,504**	18,213
Natural gas costs recoverable through rate adjustments	Up to 1 year	**41,481**	11,596
Deferred costs - MAOP (a)	-	**11,565**	6,572
Conservation activities (a)	-	**7,007**	---
Taxes recoverable from customers (a)	Over plant lives	**2,484**	2,780
Long-term debt refinancing costs (a)	Up to 19 years	**744**	837
Other (a)	Largely determined upon filing	**370**	387
Total regulatory assets		**129,109**	88,338
Regulatory liabilities:			
Plant removal costs (b)		**110,754**	115,046
Taxes refundable to customers		**77,925**	82,472
Natural gas costs refundable through rate adjustments		**26,247**	27,821
Conservation activities (b)		**---**	5,898
Other (b)		**15,927**	6,011
Total regulatory liabilities		**230,853**	237,248
Net regulatory position		**$(101,744)**	$(148,910)

* *Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.*
(a) Included in deferred charges and other assets - other on the Consolidated Balance Sheets.
(b) Included in deferred credits and other liabilities - other 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. As of December 31, 2018 and 2017, approximately $125.9 million and $84.7 million, respectively, of regulatory assets were not earning a rate of return.

In the fourth quarter of 2017, the Company performed a one-time revaluation of the Company's regulated deferred tax assets and liabilities for the reduction of the corporate tax rate from 35 percent to 21 percent effective January 1, 2018, as identified in the TCJA. In the fourth quarter of 2017, the revaluation of the deferred tax assets and liabilities resulted in a decrease of $8.2 million in taxes recoverable from customers and an increase of $78.9 million in taxes refundable to customers. The revaluation of the Company's regulatory deferred tax assets and liabilities were deferred as the Company worked with the various regulators to plan for amounts expected to be returned to customers. All amounts related to the TCJA are reserved or are being passed back to customers. The Company has tax settlements in place in most jurisdictions, with new rates in place in 2018 or expected to be in place in the first half of 2019. TCJA filings are pending in Wyoming and Oregon. For more information on the various rate cases, see Note 10. There were no significant changes between the preliminary estimate and final determination of taxes refundable to or recoverable from customers. These regulatory amounts will largely be refunded over the remaining life of the related assets.

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 or accumulated other comprehensive income (loss) 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 $3.4 million and $3.6 million as of December 31, 2018 and 2017, respectively, are classified as Investments on the Consolidated Balance Sheets. The net unrealized gains (losses) on these investments for the years ended December 31, 2018 and 2017 were ($164,000) and $430,000, respectively. The change in fair value, which is considered part of the cost of the plan, is classified in other income on the Consolidated Statements of Income. In connection with the adoption of ASU 2017-07, as discussed in Note 1, the Company has elected to reclassify prior period unrealized gains from operation and maintenance expense to other income on the Consolidated Statements of Income.

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 are valued at the net asset value of shares held at the end of the period, based on published market quotations on active markets, or using other known 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.

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, 2018 and 2017, there were no transfers between Levels 1 and 2.
The Company’s assets measured at fair value on a recurring basis were as follows:

	Fair Value Measurements at December 31, 2018, 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, 2018
	(In thousands)			
Assets:				
Money market funds	$ ---	$ 1,915	$---	$ 1,915
Insurance contract*	---	3,419	---	3,419
Total assets measured at fair value	$ ---	$ 5,334	$---	$ 5,334

** The insurance contract invests approximately 53 percent in fixed-income investments, 21 percent in common stock of large-cap companies, 11 percent in common stock of mid-cap companies, 10 percent in common stock of small-cap companies, 3 percent in target date investments and 2 percent in cash equivalents.*

	Fair Value Measurements at December 31, 2017, 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, 2017
	(In thousands)			
Assets:				
Money market funds	$ ---	$ 363	$---	$ 363
Insurance contract*	---	3,583	---	3,583
Total assets measured at fair value	$ ---	$ 3,946	$---	$ 3,946

** The insurance contract invests approximately 49 percent in fixed-income investments, 23 percent in common stock of large-cap companies, 14 percent in common stock of mid-cap companies, 11 percent in common stock of small-cap companies, 2 percent in target date investments and 1 percent in cash equivalents.*

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, whenever events or changes in circumstances indicate that such carrying amounts may not be recoverable.

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:

	2018		2017	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$ 567,258**	**$ 631,798**	$ 519,601	$ 566,811

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. At December 31, 2018, the Company complied with all applicable financial covenants and restrictions. 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, 2018	Amount Outstanding at December 31, 2017	Letters of Credit at December 31, 2018	Expiration Date
			(Dollars in millions)			
Cascade Natural Gas Corporation	Revolving credit agreement	$ 75.0 (a)	$ 53.9	$ 17.3	$ 2.2 (b)	4/24/20
Intermountain Gas Company	Revolving credit agreement	$ 85.0 (c)	$ 56.3	$ 40.0	$ ----	4/24/20

(a) Certain provisions allow for increased borrowings, up to a maximum of $100.0 million.
(b) Outstanding letters of credit reduce the amount available under the credit agreement.
(c) Certain provisions allow for increased borrowings, up to a maximum of $110.0 million.

The following includes information related to the preceding table.

Long-term debt

Cascade Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

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. Cascade's ratio of total debt to total capitalization at December 31, 2018, was 51 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.

Intermountain Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

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. Intermountain's ratio of total debt to total capitalization at December 31, 2018, was 49 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:

	2018	2017
	(In thousands)	
Senior Notes at a weighted average rate of 4.35%, due on dates ranging from October 22, 2022 to January 15, 2055	**$ 385,000**	$ 390,273
Medium-Term Notes at a weighted average rate of 6.68%, due on dates ranging from September 1, 2020 to March 16, 2029	**50,000**	50,000
Credit agreement at a rate of 4.40%, due on April 24, 2020	**110,100**	57,300
Other note at a rate of 5.25%, due on February 1, 2035	**24,361**	24,431
Unamortized debt issuance costs	**(2,203)**	(2,403)
Total long-term debt	**567,258**	519,601
Less current maturities	**---**	5,273
Net long-term debt	**$ 567,258**	$ 514,328

Schedule of Debt Maturities Long-term debt maturities, which excludes unamortized debt issuance costs and discount for the five years and thereafter following December 31, 2018, were as follows:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Long-term debt maturities	---	$125,100	---	$11,500	$46,500	$386,361

NOTE 6 – ASSET RETIREMENT OBLIGATIONS

The Company records obligations related to retirement costs of natural gas distribution mains and lines as asset retirement obligations.

A reconciliation of the Company's liability, which is included in deferred credits and other liabilities – other on the Consolidated Balance Sheets, for the years ended December 31 was as follows:

	2018	2017
	(In thousands)	
Balance at beginning of year	**$ 139,362**	$ 124,418
Liabilities incurred	**6,009**	8,743
Liabilities settled	**(1,070)**	(924)
Accretion expense (related to regulatory assets)	**7,879**	7,125
Revisions in estimates	**1,151**	---
Balance at end of year	**$ 153,331**	$139,362

The Company believes that largely all 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, 2018 and 2017 was $25,375 and $36,314, respectively.

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

	2018	2017
	(In thousands)	
Current:		
Federal	**$ (3,258)**	$ 3,997
State	**(361)**	1,196
	(3,619)	5,193
Deferred:		
Income taxes –		
Federal	**4,403**	11,841
State	**841**	(127)
Investment tax credit - net	**227**	(253)
	5,471	11,461
Total income tax expense	**$ 1,852**	$ 16,654

In accordance with the accounting guidance on accounting for income taxes, the tax effects of the change in tax laws or rates are to be recorded in the period of enactment. The TCJA was enacted on December 22, 2017, as discussed in Note 1. Therefore, the reduction in the corporate tax rate from 35 percent to 21 percent required the Company to prepare a one-time revaluation of the Company's deferred tax assets and liabilities in the fourth quarter of 2017, the period of enactment. The deferred taxes associated with the non-regulated operations were revalued at the new tax rate because deferred taxes should reflect what the Company expects to pay or receive in future periods under the applicable tax rate. As a result of the revaluation, the Company reduced the value of these assets and liabilities and recorded a tax expense of $3.5 million on the Consolidated Statements of Income for the year ended December 31, 2017. Included in the tax expense was $246,000 related to amounts in accumulated other comprehensive loss.

The Company's regulated operations prepared a one-time revaluation of the Company's regulatory deferred tax assets and liabilities in the fourth quarter of 2017 related to the enactment of the TCJA. The revaluation is being deferred under regulatory accounting as the Company works with the various regulators to plan for amounts expected to be returned to customers, as discussed in Notes 3 and 10. The revaluation of the deferred tax assets and liabilities resulted in a net decrease of $87.1 million in the fourth quarter of 2017. There were no significant changes between the preliminary estimate and final determination of taxes refundable to or recoverable from customers. These regulatory amounts will largely be refunded over the remaining life of the related assets.

The changes included in the TCJA were broad and complex. The SEC issued rules which were affirmed by the FASB as also acceptable for non-public entities that allowed for a measurement period of up to one year after the enactment date of the TCJA to finalize the recording of the related tax impacts. The Company has reviewed the impacts of the TCJA and completed its assessment of the transitional impacts during the period ending December 31, 2018, of which there were no such material adjustments.

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

	2018	2017
	(In thousands)	
Deferred tax assets:		
Legal and environmental contingencies	**$ 2,864**	$ 3,198
Accrued pension costs	**7,746**	7,991
Other	**7,801**	7,154
Total deferred tax assets	**18,411**	18,343
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**87,184**	85,449
Postretirement	**12,440**	11,996
Other	**16,412**	8,622
Total deferred tax liabilities	**116,036**	106,067
Net deferred income tax liability	**$ (97,625)**	$ (87,724)

As of December 31, 2018 and 2017, 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, 2017, to December 31, 2018, to deferred income tax expense:

	2018
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 9,901**
Deferred taxes associated with other comprehensive loss	**(405)**
Deferred taxes associated with TCJA enactment	**(3,918)**
Other	**(107)**
Deferred income tax expense for the period	**$ 5,471**

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,	2018 Amount	2018 %	2017 Amount	2017 %
	(Dollars in thousands)			
Computed tax at federal statutory rate	**$ 5,329**	**21.0**	$ 12,710	35.0
Increases (reductions) resulting from:				
State income taxes, net of federal income tax	**622**	**2.5**	1,110	3.1
TCJA revaluation	**---**	**---**	3,236	8.9
Excess deferred income tax amortization	**(3,918)**	**(15.4)**	---	---
Flow-through	**182**	**0.7**	580	1.6
TCJA revaluation related to accumulated other comprehensive income	**---**	**---**	246	0.7
AFUDC equity	**112**	**0.4**	(503)	(1.4)
Amortization of deferral of investment tax credit	**227**	**0.9**	(253)	(0.7)
Resolution of tax matters and uncertain tax positions	**102**	**0.4**	(197)	(0.5)
Other	**(804)**	**(3.2)**	(275)	(0.8)
Total income tax expense	**$ 1,852**	**7.3**	$ 16,654	45.9

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 income tax examinations by tax authorities for years ending prior to 2015. As of December 31, 2018, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2014.

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

	2018	2017
	(In thousands)	
Balance at beginning of year	**$ ---**	$ ---
Additions based on tax positions related to current year	**40**	---
Additions for tax positions of prior years	**72**	---
Balance at end of year	**$ 112**	$ ---

Included in income tax expense is interest on uncertain tax positions. For the years ended December 31, 2018 and 2017, the Company recognized approximately ($10,000) and $3,000, respectively, of interest (income) expense in income tax expense. The Company had accrued liabilities of approximately $0 and $16,000 at December 31, 2018 and 2017, respectively, for the payment of interest.

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NOTE 8 – CASH FLOW INFORMATION

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

	2018	2017
	(In thousands)	
Interest, net of AFUDC-borrowed of $660 and $336 in 2018 and 2017, respectively	**$ 22,885**	$ 23,586
Income taxes paid, net	**$ 12,187**	$ 3,092

Noncash investing transactions at December 31 were as follows:

	2018	2017
	(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 18,922**	$ 7,661

NOTE 9 – EMPLOYEE BENEFIT PLANS

Pension and other postretirement benefit plans

The Company has a noncontributory qualified defined benefit pension plan 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.

Prior to 2017, the defined benefit pension plan benefits and accruals were frozen. The Company's pension assets are included in MDU's master trust. In October 2018, the Company transferred the liability of certain participants in the defined benefit pension plan, who are currently receiving benefits, to an annuity company. The transfer of the benefit payments for these participants reduces the Company's liability and future premiums.

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 had 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 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 was 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, 2018 and 2017 and amounts recognized in the Consolidated Balance Sheets at December 31, 2018 and 2017, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 92,856**	$ 91,107	**$ 20,474**	$ 20,499
Service cost	**---**	---	**197**	210
Interest cost	**3,057**	3,406	**633**	730
Plan participants' contributions	**---**	---	**400**	392
Actuarial (gain) loss	**(6,979)**	3,910	**(2,493)**	(63)
Benefits paid	**(7,350)**	(5,567)	**(1,367)**	(1,294)
Benefit obligation at end of year	**81,584**	92,856	**17,844**	20,474
Change in net plan assets:				
Fair value of plan assets at beginning of year	**84,418**	78,920	**21,674**	20,077
Actual gain (loss) on plan assets	**(4,929)**	11,065	**(663)**	2,230
Employer contribution	**---**	---	**147**	269
Plan participants' contributions	**---**	---	**400**	392
Benefits paid	**(7,350)**	(5,567)	**(1,367)**	(1,294)
Fair value of net plan assets at end of year	**72,139**	84,418	**20,191**	21,674
Funded status – over (under)	**$ (9,445)**	$ (8,438)	**$ 2,347**	$ 1,200
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	**$ ---**	$ ---	**$ 2,988**	$ 2,415
Other liabilities (noncurrent)	**(9,445)**	(8,438)	**(641)**	(1,215)
Net amount recognized	**$ (9,445)**	$ (8,438)	**$ 2,347**	$ 1,200
Amounts recognized in regulatory assets (liabilities) consist of:				
Actuarial loss	**$ 41,834**	$ 40,552	**$ 3,998**	$ 4,903
Prior service credit	**---**	---	**(1,371)**	(1,551)
Total	**$ 41,834**	$ 40,552	**$ 2,627**	$ 3,352

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 table above 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 are 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:

	2018	2017
	(In thousands)	
Projected benefit obligation	**$ 81,584**	$92,856
Accumulated benefit obligation	**$ 81,584**	$92,856
Fair value of plan assets	**$ 72,139**	$84,418

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

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
		(In thousands)		
Components of net periodic benefit cost (credit):				
Service cost	**$ ---**	$ ---	**$ 197**	$ 210
Interest cost	**3,057**	3,406	**633**	730
Expected return on assets	**(4,899)**	(4,978)	**(1,211)**	(1,119)
Amortization of prior service credit	**---**	---	**(180)**	(156)
Recognized net actuarial loss	**1,567**	1,373	**286**	568
Net periodic benefit cost (credit), including amount capitalized	**(275)**	(199)	**(275)**	233
Less amount capitalized	**---**	(45)	**34**	76
Net periodic benefit cost (credit)	**(275)**	(154)	**(309)**	157
Other changes in plan assets and benefit obligations recognized in regulatory assets (liabilities):				
Net (gain) loss	**2,849**	(2,176)	**(619)**	(1,174)
Amortization of actuarial loss	**(1,567)**	(1,373)	**(286)**	(568)
Amortization of prior service credit	**---**	---	**180**	156
Total recognized in regulatory assets (liabilities)	**1,282**	(3,549)	**(725)**	(1,586)
Total recognized in net periodic benefit cost (credit) and regulatory assets (liabilities)	**$ 1,007**	$ (3,703)	**$ (1,034)**	$ (1,429)

The estimated net loss for the defined benefit pension plans that will be amortized from regulatory assets into net periodic benefit cost in 2019 is $1.2 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from regulatory assets into net periodic benefit cost in 2019 are $356,000 and $183,000, 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	
	2018	2017	**2018**	2017
Discount rate	**4.04%**	3.40%	**4.03%**	3.38%
Expected return on plan assets	**6.75%**	6.75%	**5.75%**	5.75%

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

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	**2018**	2017
Discount rate	**3.40%**	3.86%	**3.38%**	3.83%
Expected return on plan assets	**6.75%**	6.75%	**5.75%**	5.75%

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2018, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 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 25 percent to 30 percent equity securities and 70 percent to 75 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:

	2018	2017
Health care trend rate assumed for next year	**7.5% - 8.0%**	7.5% - 8.5%
Health care cost trend rate – ultimate	**4.5%**	4.5%
Year in which ultimate trend rate achieved	**2024**	2024

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, 2018:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 33	$ (29)
Effect on postretirement benefit obligation	$ 973	$ (848)

Outside investment managers manage the Company's pension and postretirement assets. 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 fair value 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 plan’s 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.

The estimated fair value of the pension plan’s Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded. The estimated fair value of the pension plan’s 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 plan’s 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 plan’s Level 1 U.S. Government securities is valued based on quoted prices on an active market.

The estimated fair value of the pension plan’s Level 2 U.S. Government 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, 2018 and 2017, 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, 2018, 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, 2018
	(In thousands)			
Assets:				
Cash equivalents	$ ---	$ 1,155	$ ---	$ 1,155
Equity securities:				
U.S. companies	2,587	---	---	2,587
International companies	---	227	---	227
Collective and mutual funds*	34,208	12,093	---	46,301
Corporate bonds	---	17,134		17,134
Municipal bonds	---	2,490	---	2,490
U.S. Government securities	112	1,382	---	1,494
Total assets measured at fair value	$ 36,907	$ 34,481	$ ---	$ 71,388

* *Collective and mutual funds invest approximately 27 percent in common stock of international companies, 31 percent in corporate bonds, 18 percent in common stock of large-cap U.S. companies, 5 percent in cash equivalents, and 19 percent in other investments.*

	Fair Value Measurements at December 31, 2017, 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, 2017
	(In thousands)			
Assets:				
Cash equivalents	$ ---	$ 909	$ ---	$ 909
Equity securities:				
U.S. companies	3,179	---	---	3,179
International companies	421	---	---	421
Collective and mutual funds*	40,929	16,139	---	57,068
Corporate bonds	---	17,855		17,855
Municipal bonds	---	4,011	---	4,011
U.S. Government securities	247	---	---	247
Total assets measured at fair value	$ 44,776	$ 38,914	$ ---	$ 83,690

* *Collective and mutual funds invest approximately 31 percent in common stock of international companies, 28 percent in corporate bonds, 19 percent in common stock of large-cap U.S. companies, 7 percent in cash equivalents, 1 percent in U.S. Government securities, and 14 percent in other investments.*

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 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. 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, 2018 and 2017, there were no transfers between Levels 1 and 2.

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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, 2018, 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, 2018
			(In thousands)	
Assets:				
Cash equivalents	$ ---	$ 967	$ ---	$ 967
Equity securities:				
U.S. companies	653	---	---	653
International companies	---	2	---	2
Insurance contract*	1	18,568	---	18,569
Total assets measured at fair value	$ 654	$ 19,537	$ ---	$ 20,191

** The insurance contract invests approximately 51 percent in corporate bonds, 23 percent in common stock of large-cap U.S. companies, 7 percent in U.S. Government securities, 7 percent in common stock of small-cap U.S. companies and 12 percent in other investments.*

	Fair Value Measurements at December 31, 2017, 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, 2017
			(In thousands)	
Assets:				
Cash equivalents	$ ---	$ 1,181	$ ---	$ 1,181
Equity securities:				
U.S. companies	891	---	---	891
International companies	4	---	---	4
Insurance contract*	3	19,595	---	19,598
Total assets measured at fair value	$ 898	$ 20,776	$ ---	$ 21,674

** The insurance contract invests approximately 38 percent in corporate bonds, 23 percent in common stock of large-cap U.S. companies, 21 percent in U.S. Government securities, 9 percent in mortgage-backed securities, and 9 percent in other investments.*

The Company does not expect to contribute to its defined benefit pension plan or postretirement benefit plans in 2019.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies at December 31, 2018, are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2019	4,720	1,239	1
2020	4,828	1,161	1
2021	4,871	1,146	1
2022	4,998	1,162	1
2023	5,104	1,165	1
2024-2028	25,868	5,880	2

Nonqualified benefit plans
In addition to the qualified defined benefit pension plan 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, upon death, to their beneficiaries 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. In February 2016, the Company froze the unfunded, nonqualified defined benefit plans to new participants and eliminated benefit increases. Vesting for participants not fully vested was retained.

The projected benefit obligation and accumulated benefit obligation for these plans at December 31 were as follows:

	2018	2017
	(In thousands)	
Projected benefit obligation	**$ 12,908**	$ 14,216
Accumulated benefit obligation	**$ 12,908**	$ 14,216

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

		2018	2017
		(In thousands)	
Components of net periodic			
Interest cost	**$**	**451** $	506
Recognized net actuarial loss		**553**	521
Net periodic benefit cost	**$**	**1,004** $	1,027

Weighted average assumptions used at December 31 were as follows:

	2018	2017
Benefit obligation discount rate	**3.93%**	3.27 %
Benefit obligation rate of compensation increase	**N/A**	N/A
Net periodic benefit cost discount rate	**3.26%**	3.65 %
Net periodic benefit cost rate of compensation increase	**N/A**	N/A

The amount of future benefit payments for the unfunded, nonqualified benefit plans at December 31, 2018, are expected to aggregate as follows:

		2019	2020	2021	2022	2023	Thereafter
				(In thousands)			
Nonqualified benefits	$	1,088 $	1,066 $	1,042 $	935 $	908 $	4,407

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Costs incurred under this plan for 2018 and 2017 were $57,000 and $85,000, respectively.

The amount of investments that the Company anticipates using to satisfy obligations under these plans at December 31 was as follows:

		2018	2017
		(In thousands)	
Investments			
Insurance contract*	$	**3,419** $	3,583
Life insurance**		**7,191**	7,903
Other		**1,919**	363
Total investments	$	**12,529** $	11,849

* For more information on the insurance contract, see Note 4.
**Investments of life insurance are carried on plan participants (payable upon the employee's death).

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 2018 and $3.8 million in 2017.

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 2018 and 2017 is for the plan's year-end at December 31, 2017, and December 31, 2016, 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 2018	Pension Protection Act Zone Status 2017	FIP/RP Status Pending/ Implemented	Contributions 2018	Contributions 2017	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)			
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2018	Green as of 5/31/2017	No	**$ 1,247**	$ 1,156	No	09/30/2019

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 as of December 31, 2017 and 2016.

NOTE 10 – REGULATORY MATTERS

The Company regularly reviews the need for natural gas rate changes in each of the jurisdictions in which service is provided. The Company files for rate adjustments to seek recovery of operating costs and capital investments, as well as reasonable returns as allowed by regulators. The Company's most recent cases by jurisdiction are discussed in the following paragraphs. The Company has furnished plans to the jurisdictions in which the Company provides service for the effect of the reduced corporate tax rate due to the enactment of the TCJA which may impact the Company's rates. The following paragraphs include additional details and statuses of each open jurisdiction's request.

OPUC

On December 29, 2017, Cascade filed a request with the OPUC to use deferral accounting for the 2018 net benefits associated with the implementation of the TCJA. The deferral request was renewed on December 28, 2018. This matter is pending before the OPUC.

On May 31, 2018, Cascade filed a general rate case with the OPUC requesting an overall increase of $2.3 million or approximately 3.5 percent on an annual basis, which incorporates the impact of the TCJA. On January 22, 2019, Cascade filed an all-party settlement with the OPUC for an annual increase in revenues of $1.7 million with a $500,000 reduction for excess deferred income taxes, for a net increase of $1.2 million. The OPUC issued an order on March 14, 2019, approving the settlement. The increase becomes effective on April 1, 2019.

WUTC
On June 1, 2018, Cascade filed its annual pipeline cost recovery mechanism requesting an increase in annual revenue of $2.3 million or approximately 1.1 percent. On October 11, 2018, Cascade filed a revised increase in annual revenue of $2.1 million or approximately 1.0 percent. The increase was effective November 1, 2018.

NOTE 11 – COMMITMENTS AND CONTINGENCIES

Claims and Litigation

The Company is party to claims and lawsuits arising out of its business. 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. Accruals are based on the best information available, but in certain situations management is unable to estimate an amount or range of a reasonably possible loss including, but not limited to when: (1) the damages are unsubstantiated or indeterminate, (2) the proceedings are in the early stages, (3) numerous parties are involved, or (4) the matter involves novel or unsettled legal theories. The Company accrued liabilities of $13.2 million and $14.3 million for contingencies including litigation and environmental matters at December 31, 2018 and 2017, respectively. This includes amounts that may have been accrued for matters discussed in Environmental matters within this note. The Company will continue to monitor each matter and adjust accruals as might be warranted based on new information and further developments. Management believes that the outcomes with respect to probable and reasonably possible losses in excess of the amounts accrued, net of insurance recoveries, while uncertain, either cannot be estimated or will not have a material effect upon the Company's financial position, results of operations or cash flows. Unless otherwise required by GAAP, legal costs are expensed as they are incurred.

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

The first claim is for contamination at a site in Eugene, Oregon, which was received in 1995. The Oregon DEQ released an ROD in January 2015 that selected a remediation alternative for the site as recommended in an earlier staff report. The total estimated cost for the selected remediation, including long-term maintenance, is approximately $3.5 million of which $400,000 has been incurred. Cascade and other PRPs will share in the cleanup costs with Cascade expecting to pay approximately 50 percent of the remediation and maintenance costs. Cascade has an accrual balance of $1.5 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 orders reauthorizing the deferred accounting for the 12-month periods starting November 30, 2013, December 1, 2014, December 1, 2015, December 1, 2016, December 1, 2017 and December 1, 2018.

The second claim is for contamination at the Bremerton Gasworks Superfund 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. In April 2010, the Washington DOE 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. Current estimates for the cost to complete the remedial investigation and feasibility study are approximately $7.6 million of which $3.1 million has been incurred. Cascade has accrued $4.5 million for the remedial investigation and feasibility study, as well as $6.4 million for remediation of this site; however, the accrual for remediation costs will be reviewed and adjusted, if necessary, after completion of the remedial investigation and feasibility study. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs incurred in relation to the environmental remediation of this site. 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. Other PRPs reached an agreed order and work plan with the Washington DOE for completion of a remedial investigation and feasibility study for the site. A feasibility study prepared in March 2018 identifies five cleanup action alternatives for the site with estimated costs ranging from $8.0 million to $20.4 million with a selected preferred alternative having an estimated total cost of $9.3 million. 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 recorded an accrual for this site for an amount that is not material.

Cascade has received notices from and entered into agreement with certain of its insurance carriers that they will participate in defense of Cascade for certain of the contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. Cascade received insurance payments of $29,000 and $45,000 in 2018 and 2017, respectively, for the Eugene defense costs and $2.3 million and $1.2 million in 2018 and 2017, respectively, for the Bremerton defense costs. To the extent these claims are not covered by insurance, Cascade intends to seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

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, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
	(In thousands)					
Operating leases	$237	$216	$163	$63	$39	$156

Rent expense was $577,000 and $546,000 for the year ended December 31, 2018 and 2017, 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. The commitment terms vary in length, up to 42 years.

The commitments under these contracts as of December 31, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
	(In thousands)					
Purchase commitments	$187,979	$124,212	$107,400	$93,831	$64,686	$591,519

These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2018 and 2017, respectively, were approximately $157.5 million and $162.8 million.

Guarantees

Cascade has an outstanding letter of credit to a third party related to a remedial investigation feasibility study. At December 31, 2018, the fixed maximum amount guaranteed under this letter of credit was $2.2 million, which is scheduled to expire in 2019. There were no amounts outstanding under this letter of credit at December 31, 2018.

NOTE 12 – 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 $43.8 million and $32.0 million for the years ended December 31, 2018 and 2017, respectively and the amount charged for services received from the Company was $1.3 million and $1.1 million for the years ended December 31, 2018 and 2017, respectively.

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

	2018	2017
	(In thousands)	
Accounts receivable	**$ 263**	$ 2
Accounts payable	**3,466**	2,634
Dividend payable	**4,400**	4,800
Deferred charges and other assets - other	**7,470**	6,719
Deferred credits and other liabilities - other	**1,353**	1,676

MDU has several stock-based compensation plans in which the Company participates. Total stock-based compensation expense for the years ended December 31, 2018 and 2017, respectively, was $1.1 million and $676,000, net of income taxes of $357,000 and $432,000, respectively. As of December 31, 2018, total remaining unrecognized compensation expense related to stock-based compensation was approximately $1.4 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

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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)	1,054,152,347
4	Property Under Capital Leases	
5	Plant Purchased or Sold	
6	Completed Construction not Classified	23,074,397
7	Experimental Plant Unclassified	
8	TOTAL Utility Plant (Total of lines 3 thru 7)	1,077,226,744
9	Leased to Others	
10	Held for Future Use	
11	Construction Work in Progress	12,854,207
12	Acquisition Adjustments	
13	TOTAL Utility Plant (Total of lines 8 thru 12)	1,090,080,951
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	490,730,756
15	Net Utility Plant (Total of lines 13 and 14)	599,350,195
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	473,404,421
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	17,326,335
22	TOTAL In Service (Total of lines 18 thru 21)	490,730,756
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)	490,730,756

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		1,054,152,347		
4				
5				
6		23,074,397		
7				
8		1,077,226,744		
9				
10				
11		12,854,207		
12				
13		1,090,080,951		
14		490,730,756		
15		599,350,195		
16				
17				
18		473,404,421		
19				
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21		17,326,335		
22		490,730,756		
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32				
33		490,730,756		

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	12/31/2018	End of 2018/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	43,233,241	938,054
5	TOTAL Intangible Plant (Enter Total of lines 2 thru 4)	43,597,132	938,054
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		

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	12/31/2018	End of 2018/Q4

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				44,171,295
5				44,535,186
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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	12/31/2018	End of 2018/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	12/31/2018	End of 2018/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)
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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	12/31/2018	End of 2018/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	22,244,572	
87	368 Compressor Station Equipment		
88	369 Measuring and Regulating Station Equipment	192,301	
89	370 Communication Equipment		
90	371 Other Equipment		
91	372 Asset Retirement Costs for Transmission Plant	88,011	
92	TOTAL Transmission Plant (Enter Totals of lines 83 thru 91)	23,775,509	
93	DISTRIBUTION PLANT		
94	374 Land and Land Rights	2,662,738	1,069
95	375 Structures and Improvements	1,460,862	5,035
96	376 Mains	465,650,883	42,546,603
97	377 Compressor Station Equipment	2,097,767	
98	378 Measuring and Regulating Station Equipment-General	31,749,130	1,411,963
99	379 Measuring and Regulating Station Equipment-City Gate		
100	380 Services	228,416,660	21,617,720
101	381 Meters	57,962,781	17,685,056
102	382 Meter Installations	32,866,611	895,764
103	383 House Regulators	10,687,871	926,446
104	384 House Regulator Installations		
105	385 Industrial Measuring and Regulating Station Equipment	10,530,822	1,104,836
106	386 Other Property on Customers' Premises		
107	387 Other Equipment		
108	388 Asset Retirement Costs for Distribution Plant	19,917,157	2,282,253
109	TOTAL Distribution Plant (Enter Total of lines 94 thru 108)	864,003,282	88,476,745
110	GENERAL PLANT		
111	389 Land and Land Rights	3,468,083	
112	390 Structures and Improvements	19,677,023	470,352
113	391 Office Furniture and Equipment	7,786,718	510,509
114	392 Transportation Equipment	16,598,163	1,763,264
115	393 Stores Equipment	66,925	
116	394 Tools, Shop, and Garage Equipment	7,453,063	1,666,969
117	395 Laboratory Equipment	126,158	
118	396 Power Operated Equipment	3,872,924	3,526,100
119	397 Communication Equipment	7,132,823	27,129
120	398 Miscellaneous Equipment	79,679	1,289
121	Subtotal (Enter Total of lines 111 thru 120)	66,261,559	7,965,612
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)	66,261,559	7,965,612
125	TOTAL (Accounts 101 and 106)	997,637,482	97,380,411
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)	997,637,482	97,380,411

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report End of 2018/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	72,916			22,171,656
87				
88	11,478			180,823
89				
90				
91	291			87,720
92	84,685			23,690,824
93				
94				2,663,807
95				1,465,897
96	1,780,642			506,416,844
97				2,097,767
98	119,157			33,041,936
99				
100	597,121			249,437,259
101	10,627,355			65,020,482
102	19,471	(87,608)		33,655,296
103	453,882			11,160,435
104				
105	81,439	87,608		11,641,827
106				
107				
108	102,372			22,097,038
109	13,781,439			938,698,588
110				
111				3,468,083
112	122,914			20,024,461
113	9,649			8,287,578
114	1,224,011			17,137,416
115				66,925
116	152,557			8,967,475
117	6,250			119,908
118	2,409,644			4,989,380
119				7,159,952
120				80,968
121	3,925,025			70,302,146
122				
123				
124	3,925,025			70,302,146
125	17,791,149			1,077,226,744
126				
127				
128				
129	17,791,149			1,077,226,744

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	12/31/2018	End of 2018/Q4

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				
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45	**Total**			

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				
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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	12/31/2018	End of 2018/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				
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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	12/31/2018	End of 2018/Q4

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	Construct Wallula gate station	3,581,231	
2	Anacortes lateral upgrade and main replacement	2,101,590	
3	Construct district office in Longview, WA	1,799,929	
4	Replace 12" HP main in Bend, OR	1,304,280	
5			
6			
7			
8	Minor distribution system/general Plant projects each under		
9	$1 million	4,067,177	
10			
11			
12			
13			
14			
15			
16			
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19			
20			
21			
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23			
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43			
44			
45	**Total**	**12,854,207**	

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	12/31/2018	End of 2018/Q4

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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27				
28				
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32				
33				
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35				
36				
	Total			0

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							
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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	12/31/2018	2018/Q4

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 Asset Accounting Analyst and approved by the Controller 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 (PowerPlan) 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.

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	12/31/2018	End of 2018/Q4

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 14,701,995		
	(2) Short-Term Interest			s 5.25
	(3) Long-Term Debt	D 214,431,000	48.90	d 5.27
	(4) Preferred Stock	P		p
	(5) Common Equity	C 224,513,351	51.10	c 9.40
	(6) Total Capitalization	438,944,351	100.00	
	(7) Average Construction Work In Progress Balance	W 1,058,942		

2. Gross Rate for Borrowed Funds s(S/W) + d[(D/(D+P+C)) (1-(S/W))] 5.25

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 - 5.25
   - b. Rate for Other Funds -

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	(463,301,410)	(463,301,410)		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	(26,303,413)	(26,303,413)		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Expense of Gas Plant Leased to Others				
6	Transportation Expenses - Clearing	(1,172,736)	(1,172,736)		
7	Other Clearing Accounts				
8	Other Clearing (Specify) (footnote details):	(349,590)	(349,590)		
9					
10	TOTAL Deprec. Prov. for Year (Total of lines 3 thru 8)	(27,825,739)	(27,825,739)		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	17,791,149	17,791,149		
13	Cost of Removal	3,729,701	3,729,701		
14	Salvage (Credit)	2,698,881	2,698,881		
15	TOTAL Net Chrgs for Plant Ret. (Total of lines 12 thru 14)	18,821,969	18,821,969		
16	Other Debit or Credit Items (Describe) (footnote details):	(1,099,241)	(1,099,241)		
17					
18	Book Cost of Asset Retirement Costs				
19	Balance End of Year (Total of lines 1,10,15,16 and 18)	(473,404,421)	(473,404,421)		
	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	(15,739,013)	(15,739,013)		
28	Distribution	(428,549,725)	(428,549,725)		
29	General	(29,115,683)	(29,115,683)		
30	TOTAL (Total of lines 21 thru 29)	(473,404,421)	(473,404,421)		

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	12/31/2018	End of 2018/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					587,529	2,230,775		2,818,304
2	Gas Delivered to Storage						717,293		717,293
3	Gas Withdrawn from						1,007,519		1,007,519
4	Other Debits and Credits					(190,870)			(190,870)
5	Balance at End of Year					396,659	1,940,549		2,337,208
6	Dth					62,426	549,632		612,058
7	Amount Per Dth					6.3541	3.5306		3.8186

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	12/31/2018	End of 2018/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		11,539,006	(169,918)
6	SISP Plan Assets		153,632	(14,495)
7				
8				
9				
10				
11	Account 136			
12	Short-term deposits of cash in interest			
13	bearing accounts (cash management accts)			
14				
15	Short-term deposits of cash in interest			
16	bearing accounts (Exec Deferred Compensation)			
17				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2018	End of 2018/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	(863,090)		12,232,178	(169,918)	
6			139,137	(14,495)	
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	12/31/2018	End of 2018/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	None			
2				
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4				
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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	12/31/2018	End of 2018/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				
2				
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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	130,504
2	Prepaid Rents	3,059,263
3	Prepaid Taxes	877,590
4	Prepaid Interest	
5	Miscellaneous Prepayments	429,931
6	TOTAL	4,497,288

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	12/31/2018	End of 2018/Q4

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	None						
8							
9							
10							
11							
12							
13							
14							
15	**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	12/31/2018	End of 2018/Q4

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	None						
17							
18							
19							
20							
21							
22							
23							
24							
25							
26	**Total**						

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	FAS158 Regulatory Asset	47,262,406	1,326,253				48,588,659
3	(Total System asset)						
4							
5	OR MAOP Regulatory Asset	532,792	40,131				572,923
6	(OR regulatory asset)						
7							
8	WA Conservation		7,007,263				7,007,263
9	(WA regulatory asset)						
10							
11							
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40	**Total**	47,795,198	8,373,647		0	0	56,168,845

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	12/31/2018	End of 2018/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	4,550,321	141,728	4800-4813	4,692,049	
2	(amortization period 11/10-present)					
3						
4	WA Bremerton Manufactured Gas Plant	16,285,660	106,003	9230	2,308,948	14,082,715
5	Remediation					
6						
7	WA Bellingham Manufactured Gas Plant		466,500	9230		466,500
8						
9	WA Decoupling Deferral	(5,899,263)	9,158,719	4800-4813	2,245,753	1,013,703
10						
11	WA Decoupling Adjustment	(162,307)	1,226,164	4800-4813	6,152,956	(5,089,099)
12						
13	WA MAOP Deferred Costs	6,038,694	11,447,102	9230	6,856,658	10,629,138
14						
15	OR Conservation Programs	(4,059,966)	8,010,083	4800-4813	4,394,578	(444,461)
16	(amortization period 11/10-present)			4890		
17						
18	OR Eugene Manufactured Gas Plant	1,801,566	247,219	9230	165,282	1,883,503
19	Remediation					
20						
21	OR Environmental Remediation	125,656	2,384	4800-4813	57,317	70,723
22	Cost Adjustment			4890		
23						
24	OR Intervenor Funding	58,641	99,022	4800-4813	115,496	42,167
25	(amortization period 11/10-present)			4890		
26						
27	I/C Asset - Net Benefit Funds	4,048,837	356,376			4,405,213
28						
29	Post Retirement FAS 158	2,414,473	877,413	9260	303,312	2,988,574
30						
31	ARO	45,360,249	3,801,666		154,127	49,007,788
32						
33	LOC Commitment Fee	177,725		181	177,725	
34						
35						
36						
37						
38						
39	Miscellaneous Work in Progress					
40	**Total**	70,740,286	35,940,379		27,624,201	79,056,464

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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	12/31/2018	End of 2018/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	16,343,135	1,215,917	2,009,465
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	16,343,135	1,215,917	2,009,465
6	Other (Specify) (footnote details)			
7	TOTAL Account 190 (Total of lines 5 thru 6)	16,343,135	1,215,917	2,009,465
8	Classification of TOTAL			
9	Federal Income Tax	15,031,334	1,160,633	1,882,988
10	State Income Tax	1,311,801	55,284	126,477
11	Local Income Tax			

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report End of 2018/Q4

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	152,659	114,241		(9,677,871)		(9,674,133)	17,102,003
4			footnote		footnote		
5	152,659	114,241		(9,677,871)		(9,674,133)	17,102,003
6							
7	152,659	114,241		(9,677,871)		(9,674,133)	17,102,003
8							
9	143,147	107,821		(9,669,251)		(9,662,010)	15,725,604
10	9,512	6,420		(8,620)		(12,123)	1,376,399
11							

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report End of 2018/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				
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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	12/31/2018	End of 2018/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	222,117,553
3				
4	Represents excess received over $1.00 par value			
5	of common stock			
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40	**Total**		**1,000**	**222,117,553**

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	12/31/2018	End of 2018/Q4

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		
3		
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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	12/31/2018	End of 2018/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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	TOTAL	

CAPITAL STOCK EXPENSE (ACCOUNT 214)

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

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

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

1. Furnish a supplemental statement briefly describing security financing and refinancing transactions during the year and the accounting for the securities, discounts, premiums, expenses, and related gains or losses. Identify as to Commission authorization numbers and dates.
2. Provide details showing the full accounting for the total principal amount, par value, or stated value of each class and series of security issued, assumed, retired, or refunded and the accounting for premiums, discounts, expenses, and gains or losses relating to the securities. Set forth the facts of the accounting clearly with regard to redemption premiums, unamortized discounts, expenses, and gain or losses relating to securities retired or refunded, including the accounting for such amounts carried in the respondent's accounts at the date of the refunding or refinancing transactions with respect to securities previously refunded or retired.
3. Include in the identification of each class and series of security, as appropriate, the interest or dividend rate, nominal date of issuance, maturity date, aggregate principal amount, par value or stated value, and number of shares. Give also the issuance of redemption price and name of the principal underwriting firm through which the security transactions were consummated.
4. Where the accounting for amounts relating to securities refunded or retired is other than that specified in General Instruction 17 of the Uniform System of Accounts, cite the Commission authorization for the different accounting and state the accounting method.
5. For securities assumed, give the name of the company for which the liability on the securities was assumed as well as details of the transactions whereby the respondent undertook to pay obligations of another company. If any unamortized discount, premiums, expenses, and gains or losses were taken over onto the respondent's books, furnish details of these amounts with amounts relating to refunded securities clearly earmarked.

None

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report End of 2018/Q4

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				
5	Medium Term Notes	09/15/1997	09/15/2027	20,000,000
6	Medium Term Notes	03/16/1999	03/16/2029	15,000,000
7	Insured Quarterly Notes	02/01/2005	02/01/2035	24,361,000
8	Notes	09/01/2005	09/01/2020	15,000,000
9	Senior Notes	03/08/2007	03/08/2037	40,000,000
10	Senior Notes (Series A)	08/23/2013	08/23/2025	25,000,000
11	Senior Notes (Series B)	08/23/2013	08/23/2028	25,000,000
12	Senior Notes (Series A)	11/24/2014	11/24/2044	12,500,000
13	Senior Notes (Series B)	11/24/2014	11/24/2054	12,500,000
14	Senior Notes (Series C)	01/15/2015	01/15/2045	12,500,000
15	Senior Notes (Series D)	01/15/2015	01/15/2055	12,500,000
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40	**TOTAL**			214,361,000

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report End of 2018/Q4

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					
5	7.480	1,496,000			
6	7.100	1,064,700			
7	5.250	1,280,899			
8	5.210	781,500			
9	5.790	2,316,000			
10	4.110	1,027,500			
11	4.360	1,090,000			
12	4.090	511,250			
13	4.240	530,000			
14	4.090	511,250			
15	4.240	530,000			
16					
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40		11,139,099			

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 7.48%	20,000,000	201,406	09/15/1997	09/15/2027
4	Medium Term Notes 7.10%	15,000,000	151,056	03/16/1999	03/16/2029
5	Insured Quarterly Notes 5.25%	30,000,000	1,947,598	02/01/2005	02/01/2035
6	Notes 5.21%	15,000,000	238,755	09/01/2005	09/01/2020
7	Senior Notes 5.79%	40,000,000	232,781	03/08/2007	03/08/2037
8	Senior Notes (Series A) 4.11%	25,000,000	151,810	08/23/2013	08/23/2025
9	Senior Notes (Series B) 4.36%	25,000,000	151,810	08/23/2013	08/23/2028
10	Revolving Credit Agreement		236,967	04/25/2017	04/24/2020
11	Senior Notes (Series A) 4.09%	12,500,000	62,455	11/24/2014	11/24/2044
12	Senior Notes (Series B) 4.24%	12,500,000	61,105	11/24/2014	11/24/2054
13	Senior Notes (Series C) 4.09%	12,500,000	62,455	01/15/2015	01/15/2045
14	Senior Notes (Series D) 4.24%	12,500,000	61,105	01/15/2015	01/15/2055
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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	65,177		6,713	58,464
4	56,225		5,035	51,190
5	908,285		55,618	852,667
6	41,474		16,178	25,296
7	148,975		7,770	141,205
8	95,429		12,584	82,845
9	106,545		10,068	96,477
10	177,726		78,990	98,736
11	55,863		2,082	53,781
12	56,267		1,527	54,740
13	56,209		2,081	54,128
14	56,522		1,527	54,995
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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	12/31/2018	End of 2018/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	7.50% Notes					
6	Due 11/15/2031 (1)	11/15/2001	39,729,000	(1,229,120)	785,271	744,300
7						
8	See footnote					
9						
10						
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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)	14,654,677
2	Reconciling Items for the Year	
3		
4	Taxable Income Not Reported on Books	
5	Section 174 costs	3,681,658
6	Interest capitalized adjustment (IRS>books)	572,491
7	263A adjustment - UNICAP	4,230
8	TOTAL	4,258,379
9	Deductions Recorded on Books Not Deducted for Return	
10	see footnote	41,505,117
11		
12		
13	TOTAL	41,505,117
14	Income Recorded on Books Not Included in Return	
15	see footnote	(6,013,415)
16		
17		
18	TOTAL	(6,013,415)
19	Deductions on Return Not Charged Against Book Income	
20	see footnote	(81,324,710)
21		
22		
23		
24		
25		
26	TOTAL	(81,324,710)
27	Federal Tax Net Income	(26,919,952)
28	Show Computation of Tax:	
29	Rate - 21.00%	
30	Estimated Tax Return Federal Income Tax	(5,653,190)
31	Adjustments: (see footnote)	(11,704)
32	Provision for Current Federal Income Tax (see footnote)	(5,664,894)
33	Oregon State Tax Calculation (see footnote)	(488,700)
34		
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	12/31/2018	End of 2018/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		83,220
3	Federal Accrued	378,997	
4	Fin 48 - current		
5	Gross Revenue		
6	Washington	471,393	
7	Oregon		
8	Dept of Energy - Oregon		36,718
9	City Franchise & Occupation		
10	Washington	1,508,461	
11	Oregon	728,132	
12	Property		
13	Washington	2,723,572	
14	Oregon		774,342
15	Payroll Taxes	120,799	
16	State Excise - Washington	2,070,940	
17			
18	Miscellaneous		
19			
20			
21			
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39			
	TOTAL	8,002,294	894,280

Name of Respondent Cascade Natural Gas Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 12/31/2018	Year/Period of Report End of 2018/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		(461,582)		(27,118)
3		(5,491,932)		(244,676)
4		71,714		
5				
6		441,440		
7		192,824		
8		85,001		
9				
10		10,034,792		
11		2,535,237		
12				
13		2,624,045		1,145
14		1,616,657		
15		2,257,641		
16		8,579,658		
17				
18		63,010		
19				
20				
21				
22				
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38				
39				
TOTAL		22,548,505		(270,649)

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	12/31/2018	End of 2018/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.

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	(488,700)	239,021			810,941
3	(5,736,608)	4,908,812			10,266,423
4	71,714				(71,714)
5					
6	441,440	452,282		460,551	
7	192,824	192,824			
8	85,001	82,771			34,488
9					
10	10,034,792	10,083,928		1,459,325	
11	2,535,237	2,553,913		709,456	
12					
13	2,625,190	2,739,179		2,609,583	
14	1,616,657	1,685,417			843,102
15	2,598,851	2,400,817		318,833	
16	8,739,013	9,082,535		1,727,418	
17					
18	63,010	63,010			
19					
20					
21					
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35					
36					
37					
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39					
TOTAL	22,778,421	34,484,509		7,285,166	11,883,240

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	12/31/2018	End of 2018/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					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15				341,210	
16				159,355	
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
TOTAL				500,565	

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	Vacation Payable	2,189,962
2	Wages Payable	1,772,825
3	Accrued 401K Defined Contributions	1,208,197
4	Variable Pay Incentive	982,534
5	Core Pipeline Imbalances	727,822
6	Oregon Weatherization Liability	720,197
7	SERP Defined Contributions	577,471
8	Oregon Low Income Bill Assistance	525,935
9	Energy Trust of Oregon Liability	346,867
10	Oregon Conservation Achievement Tariff	(473,547)
11	Other Misc Current Liabilities (agregate)	380,534
12		
13		
14		
15		
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19		
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35		
36		
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43		
44		
45	**Total**	**8,958,797**

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	(11,596,330)	805.1	66,831,408	37,539,771	(40,887,967)
2	(ammortization period 11/11-present)					
3						
4	OR Deferred Gas Costs	1,174,018	805.1	17,224,345	15,457,140	(593,187)
5	(ammortization period 11/11-present)					
6						
7	SGL Deposit	72,405	134/288.4	24,135		48,270
8	Customer Unclaimed Credits	1,009	131	2,255	1,124	(122)
9	MDUR Interco NC Payable - FAS 158	930,129	various		43,901	974,030
10	Pension Contribution	8,438,377	228.3/182	426,201	1,432,554	9,444,730
11						
12						
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45	**Total**	(980,392)		84,508,344	54,474,490	(31,014,246)

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	12/31/2018	End of 2018/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	(52,078,937)	(3,070,467)	(4,073,006)
4	Other (Define) (footnote details)			
5	Total (Enter Total of lines 2 thru 4)	(52,078,937)	(3,070,467)	(4,073,006)
6	Other (Specify) (footnote details)			
7	TOTAL Account 282 (Enter Total of lines 5 thr	(52,078,937)	(3,070,467)	(4,073,006)
8	Classification of TOTAL			
9	Federal Income Tax	(48,413,989)	(2,744,188)	(3,862,810)
10	State Income Tax	(3,664,948)	(326,279)	(210,196)
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&254	88,501,500	182.3&254	91,019,441	(53,594,339)
4							
5				88,501,500		91,019,441	(53,594,339)
6							
7				88,501,500		91,019,441	(53,594,339)
8							
9			254	87,877,793	254	90,345,853	(49,763,427)
10			182.3	623,707	182.3	673,588	(3,830,912)
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	12/31/2018	End of 2018/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	(25,378,377)	(12,845,167)	(4,669,970)
4	Other (Define) (footnote details)			
5	Total (Total of lines 2 thru 4)	(25,378,377)	(12,845,167)	(4,669,970)
6	Other (Specify) (footnote details)			
7	TOTAL Account 283 (Total of lines 5 thru	(25,378,377)	(12,845,167)	(4,669,970)
8	Classification of TOTAL			
9	Federal Income Tax	(23,061,620)	(11,812,294)	(4,402,947)
10	State Income Tax	(2,316,757)	(1,032,873)	(267,023)
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			footnote	13,691,138	footnote	15,039,165	(34,901,601)
4							
5				13,691,138		15,039,165	(34,901,601)
6							
7				13,691,138		15,039,165	(34,901,601)
8							
9				13,666,738		15,035,266	(31,839,495)
10				24,400		3,899	(3,062,106)
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	12/31/2018	End of 2018/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	Oregon Unbilled Ammortization		4009			(151,305)	(151,305)
2	Washington Unbilled Ammortization		4009			(934,952)	(934,952)
3	SFAS109 Regulatory Liability	52,094,123	282			(2,469,658)	49,624,465
4	Oregon Tax Rate Change	10,293,340	282			(1,168,782)	9,124,558
5	Regulatory Liability - Post Ret FAS158	2,333,957	186			373,023	2,706,980
6	WA Protected - Plus EDIT		4962	412,495		1,413,243	1,000,748
7	WA Protected - Plus EDIT grossup		4962	133,737		408,553	274,816
8	WA Unprotected EDIT		4962	193,484		657,045	463,561
9	WA Unprotected EDIT grossup		4962	63,608		189,945	126,337
10	WA Temp Fed Income Tax Credit		4962	370,665		1,233,865	863,200
11	WA Temp Fed Income Tax Credit grossup		4962	119,761		356,697	236,936
12	WA Diff Temp Fed Income Tax Credit					(367,551)	(367,551)
13							
14							
15							
16							
17							
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44							
45	**Total**	64,721,420		1,293,750	0	(459,877)	62,967,793

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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	12/31/2018	End of 2018/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:				

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	12/31/2018	End of 2018/Q4

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	161,603,290	160,886,676	161,603,290	160,886,676	16,285,884	17,654,340
2	100,897,968	100,868,460	100,897,968	100,868,460	15,106,021	16,276,810
3						
4						
5						
6						
7						
8	925,187	999,833	925,187	999,833		
9						
10						
11	27,132,008	27,389,122	27,132,008	27,389,122	94,156,657	89,680,849
12						
13						
14						
15						
16	125,412	114,496	125,412	114,496		
17						
18	124,553	190,273	124,553	190,273		
19	290,808,418	290,448,860	290,808,418	290,448,860		
20	3,982,745		3,982,745			
21	286,825,673	290,448,860	286,825,673	290,448,860		

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	12/31/2018	End of 2018/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					
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	12/31/2018	End of 2018/Q4

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)
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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	12/31/2018	End of 2018/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				
2					
3					
4					
5					
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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	12/31/2018	End of 2018/Q4

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Cascade Natural Gas Corporation	(1) [X] An Original (2) [ ] A Resubmission	12/31/2018	End of 2018/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				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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
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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	124,553
13		
14		
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39		
	Total	**124,553**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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.				
5					
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	Total				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	177,359,949	164,239,532
74	804.1 Liquefied Natural Gas Purchases	0	0
75	805 Other Gas Purchases	0	0
76	(Less) 805.1 Purchases Gas Cost Adjustments	37,057,421	18,917,115
77	TOTAL Purchased Gas (Total of lines 68 thru 76)	140,302,528	145,322,417
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	4,132,771	3,334,459
87	(Less) 808.2 Gas Delivered to Storage-Credit	4,963,076	4,476,230
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	59,074	65,869
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	59,074	65,869
95	813 Other Gas Supply Expenses	329,878	395,472
96	TOTAL Other Gas Supply Exp. (Total of lines 77,78,85,86 thru 89,94,95)	139,743,027	144,510,249
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, and 96)	139,743,027	144,510,249
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

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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	3,119,233	2,659,197
205	871 Distribution Load Dispatching	378,468	455,915
206	872 Compressor Station Labor and Expenses	70,484	97,924
207	873 Compressor Station Fuel and Power	0	0

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	5,290,540	4,812,466
209	875 Measuring and Regulating Station Expenses-General	644,834	747,176
210	876 Measuring and Regulating Station Expenses-Industrial	201,756	184,867
211	877 Measuring and Regulating Station Expenses-City Gas Check Station	0	0
212	878 Meter and House Regulator Expenses	1,297,445	1,696,009
213	879 Customer Installations Expenses	1,004,698	1,418,415
214	880 Other Expenses	6,062,842	5,400,145
215	881 Rents	149,387	160,999
216	TOTAL Operation (Total of lines 204 thru 215)	18,219,687	17,633,113
217	Maintenance		
218	885 Maintenance Supervision and Engineering	1,207,024	610,964
219	886 Maintenance of Structures and Improvements	21,819	2,579
220	887 Maintenance of Mains	1,850,162	2,384,129
221	888 Maintenance of Compressor Station Equipment	56,633	48,661
222	889 Maintenance of Measuring and Regulating Station Equipment-General	539,529	410,831
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial	47,779	28,554
224	891 Maintenance of Meas. and Reg. Station Equip-City Gate Check Station	0	0
225	892 Maintenance of Services	1,774,738	2,042,415
226	893 Maintenance of Meters and House Regulators	1,266,814	1,497,441
227	894 Maintenance of Other Equipment	1,203,286	564,637
228	TOTAL Maintenance (Total of lines 218 thru 227)	7,967,784	7,590,211
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	26,187,471	25,223,324
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	141,146	49,195
233	902 Meter Reading Expenses	796,415	732,825
234	903 Customer Records and Collection Expenses	5,489,472	6,091,369

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Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
235	904 Uncollectible Accounts	866,122	1,228,412
236	905 Miscellaneous Customer Accounts Expenses	7	832
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	7,293,162	8,102,633
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	4,222,388	391,844
242	909 Informational and Instructional Expenses	30,583	31,081
243	910 Miscellaneous Customer Service and Informational Expenses	342,654	68,587
244	TOTAL Customer Service and Information Expenses (Total of lines 240 thru 243)	4,595,625	491,512
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	0	0
249	913 Advertising Expenses	2,839	4,176
250	916 Miscellaneous Sales Expenses	0	0
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	2,839	4,176
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	7,483,551	8,374,821
255	921 Office Supplies and Expenses	4,162,213	3,988,348
256	(Less) 922 Administrative Expenses Transferred-Credit	357,025	368,869
257	923 Outside Services Employed	1,591,557	1,444,583
258	924 Property Insurance	81,986	72,012
259	925 Injuries and Damages	1,572,433	1,357,367
260	926 Employee Pensions and Benefits	5,779,296	6,475,079
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	0	0
263	(Less) 929 Duplicate Charges-Credit	0	0
264	930.1General Advertising Expenses	30,629	39,829
265	930.2Miscellaneous General Expenses	1,171,419	857,520
266	931 Rents	1,569,366	1,408,634
267	TOTAL Operation (Total of lines 254 thru 266)	23,085,425	23,649,324
268	Maintenance		
269	932 Maintenance of General Plant	37,362	54,984
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	23,122,787	23,704,308
271	TOTAL Gas O&M Expenses (Total of lines 97,177,201,229,237,244,251, and 270)	200,944,911	202,036,202

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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					
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12					
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24					
25	**Total**	0	0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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.)	812	23,202	59,074		
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25	**Total**		23,202	59,074		

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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23				
24				
25	**Total**			

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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	297,362
2	Lodging	28,789
3	Training materials	22,680
4	Software Maintenance	15,950
5	Commercial air service	14,158
6	Meals & entertainment	9,521
7	Vehicle mileage	944
8	Office supplies	635
9		
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24		
25	**Total**	390,039

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	12/31/2018	End of 2018/Q4

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.	205,779
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, and MDU ofr CNGC's share of	
6	corporated banking fees)	324,569
7	Director's fees (paid to MDU for CNGC's share of director's expenses)	363,054
8	Miscellaneous under $250,000	278,017
9		
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12		
13		
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16		
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21		
22		
23		
24		
25	**Total**	1,171,419

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	12/31/2018	End of 2018/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				3,486,360
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	421,599			
9	Distribution plant	24,564,007			
10	General plant	1,317,807			
11	Common plant-gas				
12	TOTAL	26,303,413			3,486,360

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	12/31/2018	End of 2018/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 c 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 de 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 nat 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			3,486,360	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			421,599	Transmission plant
9			24,564,007	Distribution plant
10			1,317,807	General plant
11				Common plant-gas
12			29,789,773	TOTAL

1DPH RI 5HVSRQGHQW &DVFDGH 1DWXUDO *DV &RUSRUDWLRQ	7KLV 5HSRUW ,V ☒ $Q 2ULJLQDO ☐ $ 5HVXEPLVVLRQ	'DWH RI 5HSRUW 0R 'D <U	<HDU 3HULRG RI 5HSRUW (QG RI 4

'HSUHFLDWLRQ 'HSOHWLRQ DQG $PRUWL]DWLRQ RI *DV 3ODQW $FFWV
$FTXLVLWLRQ $GMXVWPHQWV FRQWLQXHG

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.

6HFWLRQ %)DFWRUV 8VHG LQ (VWLPDWLQJ 'HSUHFLDWLRQ &KDUJHV

/LQH 1R	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		
10			
11			
12			
13			
14			
15			

3DUWLFXODUV &RQFHUQLQJ &HUWDLQ ,QFRPH 'HGXFWLRQV DQG ,QWHUHVW &KD

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 th 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; 426.2 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of les 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 inte 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 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.

/LQH 1R	Item (a)	Amount (b)
1	(a) Miscellaneous Amortization (Account 425)	
2		
3	(b) Miscellaneous Income Deductions (Account 426)	
4	Donations (Account 426.1)	147,336
5	Life Insurance (Account 426.2)	
6	Penalties (Account 426.3)	51
7	Expenditures for Certain Civic, Political and Related Activities	
8	(Account 426.4)	165,578
9	Other Deductions (Account 426.5)	615,677
10	Total Miscellaneous Income Deductions (Account 426)	928,642
11		
12	(c) Interest on Debt to Associated Companies (Account 430)	
13		
14	(d) Other Interest Expense (Account 431)	
15	Description Interest Rate	
16	Customer Deposits-OR Various	12,321
17	Customer Deposits-WA Various	3,105
18	Deferral Accounts-OR ***	53,465
19	Deferral Accounts-WA FERC Interest Rate	195,897
20	Interest on Short-Term Debt Various	95,052
21	Other Various	
22	Total Other Interest Expense (Account 431)	359,840
23		
24	***Accounts not amortizing-7.284% (Overall rate of return granted in the last	
25	Oregon general rate filing); Accounts amortizing-2.92%	
26		
27		
28		
29		
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31		
32		
33		
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35		

5HJXODWRU\ &RPPLVVLRQ ([SHQVHV $FFRXQW

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 r
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.

/LQH 1R	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	1RQH				
2					
3					
4					
5					
6					
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21					
22					
23					
24					
	7RWDO				

1DPH RI 5HVSRQGHQW &DVFDGH 1DWXUDO *DV &RUSRUDWLRQ	7KLV 5HSRUW ,V ; $Q 2ULJLQDO $ 5HVXEPLVVLRQ	'DWH RI 5HSRUW 0R 'D <U	<HDU 3HULRG RI 5HS (QG RI 4

5HJXODWRU\ &RPPLVVLRQ ([SHQVHV $FFRXQW

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.

/LQH 1R	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							
2							
3							
4							
5							
6							
7							
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1DPH RI 5HVSRQGHQW &DVFDGH 1DWXUDO *DV &RUSRUDWLRQ	7KLV 5HSRUW LV ; $Q 2ULJLQDO $ 5HVXEPLVVLRQ	'DWH RI 5HSRUW 0R 'D <U	<HDU 3HULRG RI 5HSRUW (QG RI 4

(PSOR\HH 3HQVLRQV DQG %HQHILWV $FFRXQW

5HSRUW EHORZ WKH LWHPV FRQWDLQHG LQ $FFRXQW (PSOR\HH 3HQVLRQV DQG

/LQH 1R	([SHQVH D	$PRXQW E
	Pensions – defined benefit plans	
	Pensions – other	
	Post-retirement benefits other than pensions (PBOP)	
	Post- employment benefit plans	
	Other (Specify)	
	Medical/Dental	
	Various	
	7RWDO	

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[Next page is 354]

'LVWULEXWLRQ RI 6DODULHV DQG :DJHV

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, P 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 a 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 use detail of other accounts, enter as many rows as necessary numbered sequentially starting with 75.01, 75.02, etc.

/LQH 1R	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	12,385,295			12,385,295
34	Customer Accounts	4,016,106			4,016,106
35	Customer Service and Informational	884,651			884,651
36	Sales				
37	Administrative and General	5,789,903			5,789,903
38	TOTAL Operation (Total of lines 28 thru 37)	23,075,955			23,075,955
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	5,089,156			5,089,156

'LVWULEXWLRQ RI 6DODULHV DQG :DJHV FRQWLQXHG

/LQH 1R	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)	5,089,156			5,089,156
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)	17,474,451			17,474,451
56	Customer Accounts (Total of line 34)	4,016,106			4,016,106
57	Customer Service and Informational (Total of line 35)	884,651			884,651
58	Sales (Total of line 36)				
59	Administrative and General (Total of lines 37 and 46)	5,789,903			5,789,903
60	Total Operation and Maintenance (Total of lines 50 thru 59)	28,165,111			28,165,111
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	28,165,111			28,165,111
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	7,578,474			7,578,474
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	7,578,474			7,578,474
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	183,337			183,337
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	183,337			183,337
75	Other Accounts (Specify) (footnote details)	982,534			982,534
76	TOTAL Other Accounts	982,534			982,534
77	TOTAL SALARIES AND WAGES	36,909,456			36,909,456

&KDUJHV IRU 2XWVLGH 3URIHVVLRQDO DQG 2WKHU &RQVXOWDWLYH 6HUYL

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 profe These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising,labor relations, and public 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, 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, 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 according to the instructions for that schedule.

/LQH 1R	Description (a)	Amount (in dollars) (b)
1	Michels Corporation	15,878,171
2	Brothers Pipeline Corp.	9,542,744
3	Northwest Metal Fab & Pipe, Inc.	7,139,642
4	Snelson Companies, Inc.	6,258,875
5	Five Rivers Construction, Inc.	1,572,022
6	Infrasource Services, LLC - Capital Work	1,390,197
7	Lockheed Martin Energy	959,126
8	Mistras Group, Inc.	910,411
9	Prosource Technologies, LLC	899,115
10	Aspect Consulting, LLC	831,969
11	AA Asphalting, LLC	569,567
12	JNR Paving, Inc.	558,887
13	Mackay & Sposito, Inc.	525,234
14	Pendleton Excavating	480,332
15	ABI Services, LLC	454,734
16	Snyder Gas Consulting, LLC	436,025
17	Parametrix, Inc. - Capital Work	359,012
18	Southern Cross Corp.	351,000
19	Parametrix, Inc. - O&M Work	346,848
20	Northwest Pipeline, LLC	332,400
21	Anchol QEA	330,073
22	McDowell Rackner & Gibson, PC	309,347
23	Deloitte & Touche, LLP	281,985
24	Black & Veatch	277,192
25	Asphalt Patch Systems, Inc.	273,060
26	Northwest Inspection, Inc.	271,035
27	Infrasource Construction, LLC - O&M Work	261,761
28	Henifin Construction, LLC	251,412
29	Other	13,206,343
30		
31		
32		
33		
34		
35		

7UDQVDFWLRQV ZLWK $VVRFLDWHG $IILOLDWHG &RPSDQLHV

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
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.

/LQH 1R	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	905,672
3			426.1	6,147
4			426.2	402,569
5			426.4	799
6			813	144,750
7			875	100,806
8			880	301,853
9			901	42,213
10			902	221,387
11			903	5,258,124
12			904	21,961
13			909	11,362
14			910	4,258
15			913	3
16			920	5,376,819
17			921	3,026,367
18			922	(158,954)
19			923	252,617
20	Goods or Services Provided for Affiliated Company			
21			925	651
22			926	19,269
23			930.1	24,240
24			930.2	388,951
25			931	1,490,035
26			932	45
27			Various	1,583,934
28				
29				
30				
31				
32				
33				
34				
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36				
37				
38				
39				
40				

1DPH RI 5HVSRQGHQW &DVFDGH 1DWXUDO *DV &RUSRUDWLRQ	7KLV 5HSRUW ,V ☒ $Q 2ULJLQDO ☐ $ 5HVXEPLVVLRQ	'DWH RI 5HSRUW 0R 'D <U	<HDU 3HULRG RI 5HS (QG RI 4

&RPSUHVVRU 6WDWLRQV

1. Report below details concerning compressor stations. Use the following subheadings: field compressor stations, products extraction compressor stations, undergro 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 numbe 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 percen jointly owned.

/LQH 1R	Name of Station and Location (a)	Number of Units at Station (b)	Certificated Horsepower for Each Station (c)	Plant Cost (d)
1	&RPSUHVVRU 6WDWLRQ DW %XUOLQJWRQ :$	1	1,350	2,000,731
2	3ODFHG LQ 6HUYLFH $XJXVW			
3				
4				
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1DPH RI 5HVSRQGHQW &DVFDGH 1DWXUDO *DV &RUSRUDWLRQ	7KLV 5HSRUW ,V ☒ $Q 2ULJLQDO ☐ $ 5HVXEPLVVLRQ	'DWH RI 5HSRUW 0R 'D <U	<HDU 3HULRG RI 5HS (QG RI 4

&RPSUHVVRU 6WDWLRQV

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 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 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 othe

/LQH 1R	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	3,328		139,294				1	
2								
3								
4								
5								
6								
7								
8								
9								
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11								
12								
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25								

1DPH RI 5HVSRQGHQW &DVFDGH 1DWXUDO *DV &RUSRUDWLRQ	7KLV 5HSRUW ,V ☒ $Q 2ULJLQDO ☐ $ 5HVXEPLVVLRQ	'DWH RI 5HSRUW 0R 'D <U	<HDU 3HULRG RI 5HS (QG RI 4

*DV 6WRUDJH 3URMHFWV

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

/LQH 1R	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)			

1DPH RI 5HVSRQGHQW &DVFDGH 1DWXUDO *DV &RUSRUDWLRQ	7KLV 5HSRUW ,V ; $Q 2ULJLQDO $ 5HVXEPLVVLRQ	'DWH RI 5HSRUW 0R 'D <U	<HDU 3HULRG RI 5HSRUW (QG RI 4

*DV 6WRUDJH 3URMHFWV

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.

/LQH 1R	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	

1DPH RI 5HVSRQGHQW &DVFDGH 1DWXUDO *DV &RUSRUDWLRQ	7KLV 5HSRUW ,V ; $Q 2ULJLQDO $ 5HVXEPLVVLRQ	'DWH RI 5HSRUW 0R 'D <U	<HDU 3HULRG RI 5HS (QG RI 4

7UDQVPLVVLRQ /LQHV

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 own 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 t 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.

/LQH 1R	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			
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21			
22			
23			
24			
25			

7UDQVPLVVLRQ 6\VWHP 3HDN 'HOLYHULHV

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, durin 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 repo 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.

/LQH 1R	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			

$X[LOLDU\ 3HDNLQJ)DFLOLWLHV

1. Report below auxiliary facilities of the respondent for meeting seasonal peak demands on the respondent's system, such as underground storage projects, liquefied 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 s 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 peakin separate plant as contemplated by general instruction 12 of the Uniform System of Accounts.

/LQH 1R	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					
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11					
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30					

***DV $FFRXQW 1DWXUDO *DV**

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 p 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 whi 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 destin 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 vo 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 t 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 informatio footnotes.

/LQH 1R	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)
	1DPH RI 6\VWHP			
2	GAS RECEIVED			
3	Gas Purchases (Accounts 800-805)		32,288,181	
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)		1,485,424	
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)		94,156,657	
16	Total Receipts (Total of lines 3 thru 15)		127,930,262	
17	GAS DELIVERED			
18	Gas Sales (Accounts 480-484)		31,391,904	
19	Deliveries of Gas Gathered for Others (Account 489.1)	303		
20	Deliveries of Gas Transported for Others (Account 489.2)	305	94,156,657	
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)		1,833,866	
28	Gas Used for Compressor Station Fuel	509		
29	Other Deliveries and Gas Used for Other Operations		23,202	
30	Total Deliveries (Total of lines 18 thru 29)		127,405,629	
31	GAS LOSSES AND GAS UNACCOUNTED FOR			
32	Gas Losses and Gas Unaccounted For		524,633	
33	TOTALS			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of lines 30 and 32)		127,930,262	

1DPH RI 5HVSRQGHQW	7KLV 5HSRUW LV	'DWH RI 5HSRUW	<HDU 3HULRG RI 5
&DVFDGH 1DWXUDO *DV &RUSRUDWLRQ	_; $Q 2ULJLQDO __ $ 5HVXEPLVVLRQ	0R 'D <U	4

6\VWHP 0DSV

)XUQLVK ILYH FRSLHV RI D V\VWHP PDS WR EH VXEPLWWHG RQH WR EH IXUQLVKHG...
JDWKHULQJ WUDQVSRUWDWLRQ DQG VDOH RI QDWXUDO JDV 1HZ PDSV QHHG QRW EH IXUQLVKHG...
E\ WKH UHVSRQGHQW VLQFH WKH GDWH RI WKH ODVW PDS ...
UHIHUHQFH VKRXOG EH PDGH LQ WKH VSDFH EHORZ WR WKH \HDU RI WKH PDSV WR EH IXUQLVKHG

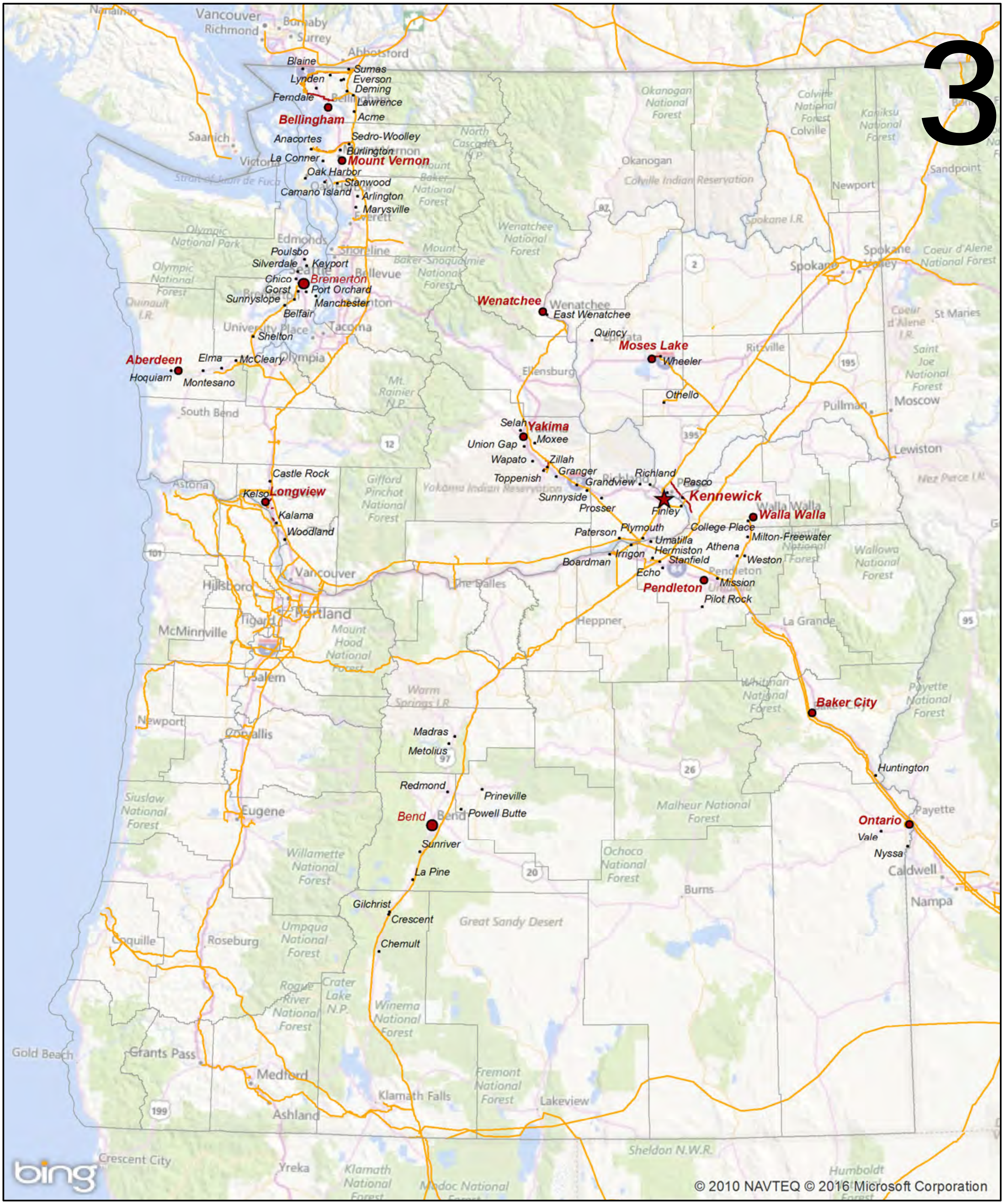
,QGLFDWH WKH IROORZLQJ LQIRUPDWLRQ RQ WKH PDSV

D 7UDQVPLVVLRQ OLQHV
E ,QFUHPHQWDO IDFLOLWLHV
F /RFDWLRQ RI JDWKHULQJ DUHDV
G /RFDWLRQ RI]RQHV DQG UDWH DUHDV
H /RFDWLRQ RI VWRUDJH ILHOGV
I /RFDWLRQ RI QDWXUDO JDV ILHOGV
J /RFDWLRQ RI FRPSUHVVRU VWDWLRQV
K 1RUPDO GLUHFWLRQ RI JDV IORZ LQGLFDWHG E\ DUURZV
L 6L]H RI SLSH
M /RFDWLRQ RI SURGXFWV H[WUDFWLRQ SODQWV VWDELOL]DWLRQ SODQWV SLSHOLQH UHF\FOLQJ DUHDV HWF
N 3ULQFLSDO FRPPXQLWLHV UHFHLYLQJ VHUYLFH WKURXJK WKH

,Q DGGLWLRQ VKRZ RQ HDFK PDS D JUDSKLF VFDOH ... D OHJHQG ...
DEEUHYLDWLRQV XVHG GHVLJQDWLRQV ...

0DSV QRW ODUJHU WKDQ LQFKHV VTXDUH DUH GHVLUHG ,I QHFHVVDU\ ...
WR D VL]H QRW ODUJHU WKDQ WKLV UHSRUW %LQG WKH PDSV WR WKH UH

6HH DWWDFKHG PDS



CASCADE NATURAL GAS CORPORATION

In the Community to Serve

Communities Served

Communities
- Community Served
- District Office
- Region Office
- General Office

Document Path: G:\Dept\Mapping\SYSTEM MAP\System Map.mxd /Date: 3/11/2016

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

5HJXODWRU\ DFFRXQWV DUHG 2WKHU FXUUHQW DGMXVWV

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

5HJXODWRU\ DFFRXQWV DUHG 2WKHU FXUUHQW DGMXVWV

Schedule Page: 260 Line No.: 8 Column: a

7KH ORVV DVVRFLDWHG ZLWK HDFK UHDFTXLVLWLRQ ZDV UHPRYHG IURP ERQGV DQG UHPDLQLQJ XQDPRUWL]HG LQ DFFRXQW RI UHDFTXLUHG GHEW DQG PDWFKHG WR WKH WHUP RI WKH UHPDLQLQJ LVVXH.

1RWHV ZHUH UHDFTXLUHG DQG UHIXQGHG E\ 1RWHV IRU GXH

7KH UHPDLQLQJ XQDPRUWL]HG GHEW H[SHQVHV ZDV UHFODVVLILHG WR XQDPRUWL]HG ORVV RQ U

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

7D[H[SHQVH
' HSUHFLDWLRQ SURYLVLRQ
5HVHUYHG UHYHQXH
9DFDWLRQ DFFUXDO FXUUHQW \HDU
,QFHQWLYH DFFUXDO
%DG 'HEW H[SHQVH
6)$6 1R DFFUXDO 6(53 6,63 DGG EDFN EN H[SHQVH
%HOOLQJKDP %UHPHUWRQ (XJHQH 0*3 H[SHQVHV
3UHSDLG H[SHQVHV
$)8'& (TXLW\
/REE\LQJ
RI EXVLQHVV PHDOV HQWHUWDLQPHQW
3D\UROO WD[HV ,QFHQWLYH DFFUXDO
$PRUW RI ORVV RQ UHDFTXLUHG GHEW
RI EXVLQHVV HQWHUWDLQPHQW
3HQDOWLHV

7RWDO

Schedule Page: 261 Line No.: 15 Column: a

7D[*DLQ ORVV RQ GLVSRVDO RI DVVHWV
&,$&
6)$6 1R SHQVLRQ SODQ DFFUXDO
5HWLUHH 0HGLFDO DFFUXDO
3HUIRUPDQFH 6KDUH SHUP

7RWDO

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

'HSUHFLDWLRQ DPRUWL]DWLRQ RI SODQW
' HIHUUHG *DV FRVWV
&RQVHUYDWLRQ SURJUDP
0$23 GHIHUUHG FRVWV
5HSDLUV GHGXFWLRQ
9DFDWLRQ DFFUXDO SULRU \HDU
)$6 DGMXVWPHQWV
%DG 'HEWV ZULWWHQ RII
6(53 6,63 SHUP GLIIHUHQFH SLHFH
6(53 EHQHILW SD\PHQWV RXW RI SODQ
&KDULWDEOH FRQWULEXWLRQV
3UHSDLG H[SHQVHV
,QFHQWLYH DFFUXDO SULRU \HDU
. 'LYLGHQGV 0'85
5HWLUHH 0HGLFDO SD\PHQWV
&XVWRPHU $GYDQFHV WR
/HJDO UHVHUYH
5R\DOW\ LQFRPH RI UR\DOW\ LQFRPH UHFHLSWV
2UHJRQ 6WDWH ,QFRPH 7D[

7RWDO

Schedule Page: 261 Line No.: 31 Column: a

'LIIHUHQFH EHWZHHQ DFFUXDO DQG WD[UHWXUQ
5 ' WD[FUHGLWV
),1 5 ' WD[FUHGLWV

7RWDO

Schedule Page: 261 Line No.: 32 Column: a

$OORFDWHG WR 7RWDO

:DVKLQJWRQ

2UHJRQ

7RWDO

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

7D[DEOH ,QFRPH IRU)HGHUDO 7D[

2UHJRQ DGMXVWPHQWV WR)HGHUDO 7D[DEOH ,QFRPH

2UHJRQ 6WDWH ,QFRPH 7D[H[SHQVH GHGXFWHG IURP)HGHUDO 5HWXUQ

%RQXV 'HSUHFLDWLRQ DGMXVWPHQW

7D[DEOH ,QFRPH IRU 2UHJRQ 7D[

2UHJRQ $SSRUWLRQPHQW)DFWRU

2UHJRQ 7D[DEOH ,QFRPH

2UHJRQ 7D[5DWH

(VWLPDWHG 7D[5HWXUQ 2UHJRQ ,QFRPH 7D[

$GMXVWPHQWV

'LIIHUHQFH EHWZHHQ DFFUXDO DQG WD[UHWXUQ

3URYLVLRQ IRU &XUUHQW 2UHJRQ ,QFRPH 7D[

$OORFDWHG WR 7RWDO

7RWDO

1DPH RI 5HVSRQGHQW	7KLV 5HSRUW LV	'DWH RI 5HSRUW	<HDU 3HULRG RI 5
&DVFDGH 1DWXUDO *DV &RUSRUDWLRQ	_; $Q 2ULJLQDO _ $ 5HVXEPLVVLRQ	0R 'D <U	4

)227127('7

Schedule Page: 276 Line No.: 3 Column: g

5HJXODWRU\ DFFRXQWV UHODWHG WR I)$6 5HJXODWRU\ $VVHW 'HIHUUHG 7D[,QFRPH 7D[5DWH ,QFUHDVH

Schedule Page: 276 Line No.: 3 Column: i

5HJXODWRU\ DFFRXQWV UHODWHG WR I)$6 5HJXODWRU\ $VVHW 'HIHUUHG 7D[,QFRPH 7D[5DWH ,QFUHDVH

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

'HSUHFLDWLRQ LV DFFUXHG PRQWKO\ RQ DQ DFFRXQW E\ DFFRXQW EDVLV EDVHG RQ WKH DF DYHUDJH EDODQFHV RI WKH EHJLQQLQJ RI WKH PRQWK DQG DW WKH H DPRXQWV VKRZQ EHORZ UHSUHVHQW WKH \HDU HQG EDODQFHV RI GHSUHFL EDVHG RQ \HDU HQG EDODQFHV LQ HDFK FDWHJRU\

Description (a)	Washington: Depreciable Plant Base (Thousands) (b)	Washington: Composite Rate (Percent) (c)	Oregon: Depreciable Plant Base (Thousands) (d)	Oregon: Composite Rate (Percent) (e)
Intangible plant	31,198		12,215	
Manufactured gas production	0		0	
Transmission plant	17,165	1.80%	6,247	1.81%
Distribution plant	711,704	2.65%	197,819	2.88%
General plant	47,247	3.89%	17,139	3.80%
Total	**807,314**	**2.92%**	**233,420**	**3.16%**

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

372 ,QFHQWLYH 6HUYHUDQFH 3D\ /LDELOLWLHV

'LYLGHQG DSSURSULDWLRQV
(DUQLQJV UHWDLQHG
([FKDQJH DQG FHUWDLQ WUDQVDFWLRQV
([SHQVHV JDV RSHUDWLRQ PDLQWHQDQFH
([WUDRUGLQDU\ SURSHUW\ ORVVHV
)LOLQJ 5HTXLUHPHQWV WKLV UHSRUW IRUP L LLL
)RRWQRWH 'DWD
*DV DFFRXQW QDWXUDO
*DV
H[FKDQJHG QDWXUDO
UHFHLYHG
VWRUHG XQGHUJURXQG
XVHG LQ XWLOLW\ RSHUDWLRQV FUHGLW
SODQW LQ VHUYLFH
*DWKHULQJ UHYHQXHV
*HQHUDO GHVFULSWLRQ RI YHULILFDWLRQ SURFHGXUHV
*HQHUDO LQIRUPDWLRQ
,QFRPH
GHGXFWLRQV GHWDLOV

VWDWHPHQW RI IRU \HDU
,QVWDOOPHQWV UHFHLYHG RQ FDSLWDO VWRFN
,QWHUHVW
RQ GHEW WR DVVRFLDWHG FRPSDQLHV
RQ ORQJ WHUP IURP LQYHVWPHQW DGYDQFHV HWF
,QVWUXFWLRQV IRU ILOLQJ WKH)(5&)RUP 1R L LLL
,QYHVWPHQW
LQ DVVRFLDWHG FRPSDQLHV
RWKHU
VXEVLGLDU\ FRPSDQLHV
VHFXULWLHV GLVSRVHG RI GXULQJ \HDU
WHPSRUDU\ FDVK
/DZ H[FHSWV DSSOLFDEOH WR WKLV UHSRUW IRUP L Y
/LVW RI 6FKHGXOHV WKLV UHSRUW IRUP
/HJDO SURFHHGLQJV GXULQJ \HDU
/RQJ WHUP GHEW
DVVXPHG GXULQJ \HDU
UHWDLQHG GXULQJ \HDU
0DQDJHPHQW DQG HQJLQHHULQJ FRQWUDFWV
0DS V\VWHP

0LVFHOODQHRXV JHQHUDO H[SHQVH
1RWHV
3D\DEOH DGYDQFHV IURP DVVRFLDWHG FRPSDQLHV
WR EDODQFH VKHHW
WR ILQDQFLDO VWDWHPHQW
WR VWDWHPHQW RI LQFRPH IRU WKH \HDU
2SHUDWLQJ
H[SHQVHV JDV
UHYHQXHV JDV
2WKHU
GRQDWLRQV UHFHLYHG IURP VWRFNKROGHUV

JDLQV RQ UHVDOH RU UHDFTXLUHG FDSLWDO VWRFN
PLVFHOODQHRXV SDLG LQ FDSLWDO
RWKHU VXSSOLHV H[SHQVH
SDLG LQ FDSLWDO
UHGXFWLRQ LQ SDU RU VWDWHG YDOXH RI FDSLWDO VWRFN
UHJXODWRU\ DVVHWV
UHJXODWRU\ OLDELOLWLHV
3HDN GHOLYHULHV WUDQVPLVVLRQ V\VWHP
3HDNLQJ IDFLOLWLHV DX[LOLDU\
3ODQW JDV
FRQVWUXFWLRQ ZRUN LQ SURJUHVV
KHOG IRU IXWXUH XVH

OHDVHG IURP RWKHUV
OHDVHG WR RWKHUV
3ODQW 8WLOLW\
DFFXPXODWHG SURYLVLRQV IRU
OHDVHG WR RWKHUV LQFRPH IURP
3UHPLXP RQ FDSLWDO VWRFN
3UHSDLG WD[HG

3UHSD\PHQWV

3URIHVVLRQDO VHUYLFHV FKDUJHV IRU
3URSHUW\ ORVVHV H[WUDRUGLQDU\
5HDFTXLUHG
FDSLWDO VWRFN
ORQJ WHUP GHEW
5HFHLYHUV¶ FHUWLILFDWH
5HFRQFLOLDWLRQ RI UHSRUWHG QHW LQFRPH ZLWK WD[DEOH LQFRPH IRU IHGHUDO LQFRPH WD[HV
5HJXODWRU\ FRPPLVVLRQ H[SHQVHV
5HJXODWRU\ FRPPLVVLRQ H[SHQVHV GHIHUUHG
5HWDLQHG HDUQLQJV
DSSURSULDWHG
VWDWHPHQW RI
XQDSSURSULDWHG
5HYHQXHV
IURP VWRULQJ JDV RI RWKHUV
IURP WUDQVSRUWDWLRQ RI JDV WKURXJK JDWKHULQJ IDFLOLWLHV
IURP WUDQVSRUWDWLRQ RI JDV WKURXJK WUDQVPLVVLRQ IDFLOLWLHV
JDV RSHUDWLQJ
6DODULHV DQG ZDJHV GLVWULEXWLRQ RI
6DOHV

6HFXULWLHV
GLVSRVHG RI GXULQJ \HDU
KROGHUV DQG YRWLQJ SRZHUV
LQYHVWPHQW LQ DVVRFLDWHG FRPSDQLHV
LQYHVWPHQW RWKHUV
LVVXHG RU DVVXPHG GXULQJ \HDU
UHIXQGHG RU UHWLUHG GXULQJ \HDU
UHJLVWHUHG RQ D QDWLRQDO H[FKDQJH

6WRFN OLDELOLW\ IRU FRQYHUVLRQ
6WRUDJH
RI QDWXUDO JDV XQGHUJURXQG
UHYHQXHV
7D[HV
DFFUXHG DQG SUHSDLG
FKDUJHG GXULQJ WKH \HDU
RQ LQFRPH GHIHUUHG   DFFXPXODWHG

UHFRQFLOLDWLRQ RI QHW LQFRPH IRU
7UDQVPLVVLRQ
DQG FRPSUHVVLRQ RI JDV E\ RWKHUV
OLQHV
UHYHQXHV
V\VWHP SHDN GHOLYHULHV
8QDPRUWL]HG
GHEW GLVFRXQW DQG H[SHQVH
ORVV DQG JDLQ RQ UHDFTXLUHG GHEW
SUHPLXP RQ GHEW
8QGHUJURXQG
VWRUDJH RI JDV DW H[SHQVH RI QDWXUDO JDV SODQW
8QUHFRYHUHG SODQW DQG UHJXODWRU\ VWXG\ FRVWV

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

Form 2 Approved
OMB No.1902-0028
(Expires /3 /20)

Form 3-Q Approved
OMB No.1902-0205
(Expires 1 /3 /201)

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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 201 /Q4

ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FORM 2
FOR MULTI-STATE GAS COMPANIES
2018

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, 2018

STATE OF OREGON - STATEMENT OF OPERATING INCOME FOR THE YEAR

LINE NO.	ACCOUNT	(REF.) PAGE NO.	GAS UTILITY	
			Current Year	Previous Year
	(a)	(b)	(c)	(d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	62,341,032	64,274,782
3	Operating Expenses			
4	Operation Expenses (401)	4-9	42,747,407	43,880,948
5	Maintenance Expenses (402)	4-9	1,738,467	1,628,355
6	Depreciation Expense (403)	10	6,154,978	5,671,347
7	Amortization & Depletion of Utility Plant (404-405)	10	909,516	766,241
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)		-	-
11	Taxes Other Than Income Taxes (408.1)	11	5,105,787	5,170,826
12	Income Taxes - Federal (409.1)	12	477,754	(726,061)
13	Income Taxes - Other (409.1)	13	(461,582)	(129,101)
14	Provision for Deferred Income Taxes (410.1)	14-21	2,444,547	2,739,613
15	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	14-21	(2,356,657)	-
16	Investment Tax Credit Adjustment - Net (411.4)	22	(9,690)	(8,719)
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)		56,750,527	58,993,449
20	Net Utility Operating Income (Enter Total of line 2 less 19)		5,590,505	5,281,333

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, 2018

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	$ 35,735,955	$ 35,525,211	4,078,092	4,373,150	64,137	61,798
3	481 Commercial and Industrial Sales						
4	Small or Commercial	$ 19,735,290	$ 20,210,186	2,836,254	3,096,877	10,061	9,947
5	Large or Industrial	$ 4,064,217	$ 4,159,797	671,341	713,664	157	152
6	482 Other Sales to Public Authorities						
7	484 Interdepartmental Sales						
8	TOTAL Sales to Ultimate Consumers	$ 59,535,462	$ 59,895,194	7,585,687	8,183,691	74,355	71,897
9	483 Sales for Resale						
10	TOTAL Natural Gas Service Revenues	$ 59,535,462	$ 59,895,194	7,585,687	8,183,691	74,355	71,897
11	Revenues from Manufactured Gas						
12	TOTAL Gas Service Revenues	$ 59,535,462	$ 59,895,194				
13	OTHER OPERATING REVENUES						
14	485 Intracompany Transfers						
15	487 Forfeited Discounts						
16	488 Miscellaneous Service Revenues	$ 146,470	$ 182,797				
17	489 Revenue from Trans. of Gas of Others	$ 4,125,680	$ 4,114,884				
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	$ 12,000				
22	494 Interdepartmental Rents	$ 28,749	$ 25,558				
23	495 Other Gas Revenues	$ 51,692	$ 44,349				
24	TOTAL Other Operating Revenues	$ 4,363,591	$ 4,379,588				
25	TOTAL Gas Operating Revenues	$ 63,899,053	$ 64,274,782				
26	(Less) 496 Provision for Rate Refunds	$ (1,558,020)					
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)	$ 55,471,245		6,914,346			
29	Main Line Industrial Sales (Incl. Main Line Sales to Public Authorities)	$ 4,064,217		671,341			
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))	$ 59,535,462		7,585,687			

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, 2018

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 Account 493 or 494.
4. Provide a subheading and total for each account.

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

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

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, 2018

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

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

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

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	32,942,897	35,281,498
73	804.1 Liquefied Natural Gas Purchases	0	0
74	805 Other Gas Purchases	0	0
75	(Less) 805.1 Purchased Gas Cost Adjustments	(3,808,349)	(4,938,895)
76	805.2 Incremental Gas Cost Adjustments	0	0
77	Total Purchased Gas (Enter Total of lines 67 to 75)	29,134,548	30,342,603
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	506,266	404,388
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	(10,870)	(13,303)
94	Total Gas Used in Utility Operations - Credit (Lines 91 thru 93)	(10,870)	(13,303)
95	813 Other Gas Supply Expenses	88,245	101,025
96	Total Other Gas Supply Exp (Lines 77, 78, 85, 86 thru 89, 94, 95)	29,718,189	30,834,713
97	Total Production Expenses (Total of lines 3, 30, 58, 65 and 96)	29,718,189	30,834,713

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, 2018

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

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, 2018

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
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

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	826,122	735,994
205	871 Distribution Load Dispatching	85,199	112,679
206	872 Compressor Station Labor and Expenses	0	0
207	873 Compressor Station Fuel and Power	0	0
208	874 Mains and Services Expenses	1,282,991	1,223,950
209	875 Measuring and Regulating Station Expenses - General	176,642	186,913
210	876 Measuring and Regulating Station Expenses - Industrial	38,171	19,763
211	877 Measuring & Regulating Station Exp - City Gate Check Station	0	0
212	878 Meter and House Regulator Expenses	231,859	458,032
213	879 Customer Installations Expenses	241,652	448,687
214	880 Other Expenses	1,884,697	1,599,521
215	881 Rents	28,789	33,201
216	Total Operation (Enter Total of lines 204 thru 215)	4,796,122	4,818,740
217	Maintenance		
218	885 Maintenance Supervision and Engineering	221,877	147,320
219	886 Maintenance of Structures and Improvements	441	179
220	887 Maintenance of Mains	415,071	336,082
221	888 Maintenance of Compressor Station Equipment	227	(1,269)
222	889 Maintenance of Meas. and Reg. Sta. Equip. - General	69,974	53,968
223	890 Maintenance of Meas. and Reg. Sta. Equip. - Industrial	5,266	8,477
224	891 Maint. of Meas. & Reg. Sta. Equip. - City Gate Check Station	0	0
225	892 Maintenance of Services	408,632	476,389
226	893 Maintenance of Meters and House Regulators	251,250	417,681
227	894 Maintenance of Other Equipment	357,562	176,967
228	Total Maintenance (Enter Total of lines 218 thru 227)	1,730,300	1,615,794
229	Total Distribution Expenses (Enter Total of lines 216 and 228)	6,526,422	6,434,534
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	35,776	12,405
233	902 Meter Reading Expenses	219,001	192,860
234	903 Customer Records and Collection Expenses	1,404,414	1,461,608
235	904 Uncollectible Accounts	171,038	237,848
236	905 Miscellaneous Customer Accounts Expenses	2	208
237	Total Customer Accounts Expenses (Total of lines 232 thru 236)	1,830,231	1,904,929
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	208,213	98,401
242	909 Informational and Instructional Expenses	2,983	5,684
243	910 Miscellaneous Customer Service and Informational Expenses	86,177	17,119
244	Total Customer Service & Information Expenses (Lines 240 thru 243)	297,373	121,204
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	0	0
249	913 Advertising Expenses	1,293	913
250	916 Miscellaneous Sales Expenses	0	0
251	Total Sales Expenses (Enter Total of lines 247 thru 250)	1,293	913

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)
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	1,882,113	2,264,862
255	921 Office Supplies and Expenses	1,057,859	1,009,853
256	(Less) 922 Administrative Expenses Transferred - Cr.	(101,231)	(96,290)
257	923 Outside Services Employed	577,828	286,641
258	924 Property Insurance	20,620	17,974
259	925 Injuries and Damages	465,943	420,394
260	926 Employee Pensions and Benefits	1,492,230	1,708,831
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	0	0
263	(Less) 929 Duplicate Charges - Cr.	0	0
264	930.1 General Advertising Expenses	8,194	10,711
265	930.2 Miscellaneous General Expenses	297,496	213,092
266	931 Rents	403,147	364,381
267	Total Operation (Enter Total lines 254 thru 266)	6,104,199	6,200,449
268	Maintenance		
269	935 Maintenance of General Plant	8,167	12,561
270	Total Administrative and General Exp (Total of lines 267 and 269)	6,112,366	6,213,010
271	Total Gas O. & M. Exp (Lines 97,177,201,229,237,244,251 and 270)	44,485,874	45,509,303

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:			
275	Production and Gathering	0	0	0
276	Products Extraction	0	0	0
277	Exploration and Development	0	0	0
278	Total Natural Gas	0	0	0
279	Other Gas Supply Expenses	29,718,189	0	29,718,189
280	Total Production	29,718,189	0	29,718,189
281	Underground Storage	0	0	0
282	Other Storage	0	0	0
283	LNG Terminiling and Processing	0	0	0
284	Transmission Expenses	0	0	0
285	Distribution Expenses	4,796,122	1,730,300	6,526,422
286	Customer Accounts Expenses	1,830,231	0	1,830,231
287	Customer Service and Informational Expenses	297,373	0	297,373
288	Sales Expenses	1,293	0	1,293
289	Admin and General Expenses	6,104,199	8,167	6,112,366
290	Total Gas O. & M. Expenses	42,747,407	1,738,467	44,485,874

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, 2018

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			909,516			909,516
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	113,173					113,173
9	Distribution Plant	5,697,374					5,697,374
10	General Plant	344,431					344,431
11	Common Plant - Gas						-
12							
13							
14							
15							
16							
17							
18							
19	TOTAL	6,154,978	-	909,516	-	-	7,064,494

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, 2018

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

LINE NO.	KIND OF TAX (a)	AMOUNT (b)
1	Property Taxes	1,685,893
2	Payroll Taxes	579,822
3	Oregon PUC Regulatory Fee	192,824
4	Oregon Department of Energy Fee	85,001
5	City Franchise Taxes	2,535,237
6	Miscellaneous Taxes	27,010
	TOTAL (Must agree with page 1, line 11)	5,105,787

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, 2018

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

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).
2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.
3. Current tax expense on this schedule must match the amount reported on page 1, line 12 of this report. Separately identify adjustments arising from revisions of prior year accruals.
4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	PARTICULARTS (Details) (a)		Amount (b)
1	Gas Operating Revenues		62,341,032
2	Operations and Maintenance Expenses		(44,485,874)
3	Taxes, Other than Income		(5,105,787)
4	State Income (Excise) Tax		(42,647)
5	Interest		(2,960,830)
6	Other Income		(57,029)
7	Federal Income Tax Depreciation		(6,990,994)
8	Other Additions (Subtractions) to Derive Taxable Income		
9	Reserved Revenue		1,558,020
10	Section 174 costs		828,741
11	STIP accrual adjustment		205,009
12	Interest capitalized adj (IRS>books)		131,138
13	50 % of business meals & entertainment		48,579
14	Vacation Accrual adjustment		24,470
15	Payroll taxes - incentive comp		23,004
16	Customer Advances - 2520.000 to 2520.2991		22,400
17	Amort of loss on reacquired debt (4281)		9,411
18	100 % of business entertainment		2,897
19	263A Adjustment - UNICAP		1,064
20	Severance accrual adjustment		-
21	Bad Debt Adjustment		(764)
22	Legal Reserve		(5,151)
23	Prepaid Expenses		(16,180)
24	MGP expense		(39,901)
25	MAOP Deferred Costs		(40,131)
26	Retiree Medical Accrual adjustment		(50,571)
27	SFAS No.87 pension plan accrual		(69,414)
28	FAS158 Adjustment		(250,973)
29	Deferred Gas Costs		(593,187)
30	CIAC		(631,872)
31	Tax Gain (loss) on disposal of assets		(639,909)
32	Repairs Deduction		(794,653)
33	Federal Tax Net Income		2,419,898
34	Show Computation of Tax:		
35	Federal Tax Rate		21%
36	Estimated Federal Tax		508,179
37	Adjustments to Estimated Federal Tax		
38	Difference between 12/31/17 accrual and tax return		54,335
39	Prior year adjustments		-
40	R&D credit		(84,760)
41	Provision for Current Federal Income Tax	409.1	477,754
42			
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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, 2018

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		286,825,673
2	Operations and Maintenance Expenses		(200,944,911)
3	Taxes, Other than Income		(28,430,305)
4	State Income (Excise) Tax		
5	Interest		(12,288,417)
6	Other Income		1,364,668
7	Federal Income Tax Depreciation		(31,497,588)
8	Other Additions (Subtractions) to Derive Taxable Income		
9	Reserved Revenue		4,156,067
10	Section 174 Costs		3,681,658
11	STIP accrual adjustment		815,145
12	MGP expense		700,960
13	Interest capitalized adj (IRS>books)		582,575
14	50 % of business meals & entertainment		164,921
15	Vacation Accrual adjustment		97,296
16	Payroll Taxes - Incentive comp		91,468
17	Amort of loss on reacquired debt (4281)		40,971
18	100 % of business entertainment		11,918
19	263A Adjustment - UNICAP		4,230
20	Severance accrual adjustment		-
21	Bad Debt Adjustment		(10,399)
22	Legal Reserve		(20,482)
23	Prepaid Expenses		(64,335)
24	Customer Advances - 2520.000 to 2520.2991		(81,567)
25	Retiree Medical Accrual adjustment		(201,078)
26	SFAS No.87 pension plan accrual		(275,999)
27	FAS158 Adjustment		(997,905)
28	CIAC		(2,807,073)
29	Tax Gain (loss) on disposal of assets:		(2,845,317)
30	Repairs Deduction		(3,530,221)
31	MAOP Deferred Costs		(4,630,574)
32	Conservation program		(6,309,806)
33	Deferred Gas Costs		(29,884,824)
34	Federal Tax Net Income		(26,283,251)
35	Oregon Apportionment Rate		23.7483%
36	State Tax Net Income		(6,241,825)
37	Show Computation of Tax:		
38	State Tax Rate		7.6%
39			(474,379)
40	Adjustments to Estimated State Tax		
41	Difference between 12/31/17 accrual and tax return		12,797
42	Prior year adjustments		-
43	Tax Retorm		-
44	Provision for Current Federal Income Tax	409.1	(461,582)
45			
46			
47			
48			
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51			
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55			

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, 2018

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			
2				
3	Other			
4	TOTAL ELECTRIC			
5	Gas	16,343,135	(1,215,917)	2009465
6				
7	Other	-		
8	TOTAL GAS	16,343,135	(1,215,917)	2,009,465
9	Other (Specify)	-		
10	TOTAL (Account 190)	16,343,135	(1,215,917)	2,009,465
11	Classification of Totals			
12	Federal Income Tax	15,031,334	(1,160,633)	1882988
13	State Income Tax	1,311,801	(55,284)	126477
14	Local Income Tax	-	-	0
15				
16	Amounts assigned to jurisdictions as follows:			
17	Federal Income Tax - Washington	See Below	(958,356)	1339724
18	Federal Income Tax - Oregon	See Below	(202,277)	543264
19	State Income Tax - Oregon	1,311,801	(55,284)	126477
20				
21				
22				

The federal Begining balance in account 190 relating to customer advances 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:
The federal Ending balance in account 190 is allocated by the source of the individual m-items.

	Beginning of Year
Federal Income Tax Acct Balance Relating to Customer Advances	1,055,801
Washington allocation factor	77.16%
Washington Allocated balance relating to Customer Advances	814,656
Oregon allocation factor	22.84%
Oregon Allocated balance relating to Customer Advances	241,145
Remaining balance to be allocated on 3-factor	13,975,533
Oregon allocation factor	24.96%
Oregon allocation	3,488,293
Plus Oregon Allocation of Customer Advances related balance	241,145
Total Oregon Allocated Balance	3,729,438

NAME OF RESPONDENT CASCADE NATURAL GAS COPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2018

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 End of Year	Line No.
		DEBITS		CREDITS			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account No.	Amount	Account No.	Amount		
(e)	(f)	(g)	(h)	(I)	(j)	(k)	
							1
							2
							3
							4
(152,659)	114,241	Regulatory accounts related to FAS 158 and OR rate change adjustments	9,677,871	Regulatory accounts related to FAS 158 and OR rate change adjustments	(9,674,133)	17,102,003	5
							6
						-	7
(152,659)	114,241		9,677,871		(9,674,133)	17,102,003	8
						-	9
(152,659)	114,241		9,677,871		(9,674,133)	17,102,003	10
							11
(143,147)	107,821		9,669,251		(9,662,010)	15,725,604	12
(9,512)	6,420		8,620		(12,123)	1,376,399	13
-	-		-		-	-	14
							15
							16
(107,145)	80,704		9,370,852		(42,047)	12,147,162	17
(36,002)	27,117		298,399		(9,619,963)	3,578,442	18
(9,512)	6,420		8,620		(12,123)	1,376,399	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, 2018

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:
   - (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, 2018

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

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

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

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

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	(52,078,937)	(3,070,467)	4,073,006
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(52,078,937)	(3,070,467)	4,073,006
6	Other (Specify)	-		
7				
8				
9	Total (Account 282) Lines 5 thru 8	(52,078,937)	(3,070,467)	4,073,006
10	Classification of Totals			
11	Federal Income Tax	(48,413,989)	(2,744,188)	3,862,810
12	State Income Tax	(3,664,948)	(326,279)	210,196
13	Local Income Tax	-	-	-
	Amounts assigned to jurisdictions as follows:			
	Federal Income Tax - Washington	See Below	(2,179,813)	2,983,822
	Federal Income Tax - Oregon	See Below	(564,375)	878,988
	State Income Tax - Oregon	(3,664,948)	(326,279)	210,196

The federal beginning 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:

The federal ending balance in account 282 is allocated based on the source of the individual M-items.

	Beginning of Year
Federal Income Tax Acct Balance Relating to utility plant for ratemaking	(100,214,084)
Washington allocation factor	77.16%
Washington Allocated balance relating to utility plant for ratemaking	(77,325,187)
Oregon allocation factor	22.84%
Oregon Allocated balance relating to utility plant for ratemaking	(22,888,897)
Remaining balance to be allocated on Utility Plant	51,800,095
Oregon allocation factor	22.55%
Oregon allocation	11,680,921
Plus Oregon Allocation of utility plant for ratemaking related balance	(22,888,897)
Total Oregon Allocated Balance	(11,207,976)

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, 2018

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
0	-	182.3 & 254	88,501,500	182.3 & 254	(91,019,441)	(53,594,339)	3
						-	4
-	-		88,501,500		(91,019,441)	(53,594,339)	5
						-	6
							7
							8
-	-		88,501,500		(91,019,441)	(53,594,339)	9
							10
-	-	254	87,877,793	254	(90,345,853)	(49,763,427)	11
-	-	182.3	623,707	182.3	(673,588)	(3,830,912)	12
-	-		-		-	-	13
-	-		3,961,566		(43,242,428)	(38,463,931)	
-	-		83,916,227		(47,103,425)	(11,299,496)	
-	-		623,707		(673,588)	(3,830,912)	

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, 2018

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited Account 411.1 (d)
1	Account 283			
2	Electric	0		
3	Gas	(25,378,377)	(12,845,167)	4,669,970
4	Other (Define)	-		
5	Total (Total of Lines 2 thru 4)	(25,378,377)	(12,845,167)	4,669,970
6	Other (Specify)	-		
7				
8				
9	Total (Account 283) Lines 5 thru 8	(25,378,377)	(12,845,167)	4,669,970
10	Classification of Totals			
11	Federal Income Tax	(23,061,620)	(11,812,294)	4,402,947
12	State Income Tax	(2,316,757)	(1,032,873)	267,023
13	Local Income Tax	-	-	-

Amounts assigned to jurisdictions as follows:

Federal Income Tax - Washington	See below	(11,548,834)	4,072,238
Federal Income Tax - Oregon	See below	(263,460)	330,709
State Income Tax - Oregon	(2,316,757)	(1,032,873)	267,023

The federal beginning 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:

The federal ending balance in account 283 is allocated based on the source of the individual m-items.

	Beginning of Year
Federal Income Tax Acct Balance Relating to Debt Refinancing	(161,931)
Washington allocation factor	77.16%
Washington Allocated balance relating to Debt Refinancing	(124,946)
Oregon allocation factor	22.84%
Oregon Allocated balance relating to Debt Refinancing	(36,985)
Remaining balance to be allocated on 3-factor	(22,899,689)
Oregon allocation factor	24.96%
Oregon allocation	(5,715,762)
Plus Oregon Allocation of Debt refinancing related balance	(36,985)
Total Oregon Allocated Balance	(5,752,747)

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, 2018

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 End of Year	Line No.
Amounts Debited Account 410.2	Amounts Credited Account 411.2	DEBITS Account No.	DEBITS Amount	CREDITS Account No.	CREDITS Amount		
(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	13,691,138	Regulatory accounts related to FAS 158 and deferred tax effect of OR State Tax Rate increase	(15,039,165)	(34,901,601)	3
						-	4
-	-		13,691,138		(15,039,165)	(34,901,601)	5
						-	6
							7
							8
-	-		13,691,138		(15,039,165)	(34,901,601)	9
							10
-	-		13,666,738		(15,035,266)	(31,839,495)	11
-	-		24,400		(3,899)	(3,062,106)	12
-	-		-		-	-	13
-	-		14,631		(990,013)	(26,957,638)	
-	-		13,652,107		(14,045,253)	(4,881,857)	
-	-		24,400		(3,899)	(3,062,106)	

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, 2018

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

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

Line No.	Account Subdivision	Balance at Beginning of Year	Deferred For Year		Allocations to Current Year's Income		Adjustments	Balance at End of Year	Average period of Allocation to Income
			Account No	Amount	Account No	Amount			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas utility								
2	3%								
3	4%	NOT			411.4	-		NOT	31 Years
4	7%				411.4	-			31 Years
5	10%	ALLOCATED			411.4	(9,690)		ALLOCATED	23 Years
6	Total	0		0		(9,690)			
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, 2018

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)	223,712,403		223,712,403			
4	Property under capital leases	-					
5	Plant purchased or sold	-					
6	Completed construction not classified	3,939,414		3,939,414			
7	Experimental plant unclassified	-					
8	TOTAL (Enter Total of lines 3 thru 7)	227,651,817	-	227,651,817	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	1,794,900		1,794,900			
12	Acquisition Adjustments	-					
13	Total Utility Plant (Enter Total of lines 8 thru 12)	229,446,717	-	229,446,717	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(98,328,316)		(98,328,316)			
15	Net Utility Plant (Line 13 less 14)	131,118,401	-	131,118,401	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(98,236,122)		(98,236,122)			
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	(92,194)		(92,194)			
22	Total In-Service (Total of lines 18 thru 21)	(98,328,316)	-	(98,328,316)	-		-
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)	(98,328,316)	-	(98,328,316)	-		-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

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	2,947,820			1		2,947,821
5	TOTAL Intangible Plant	3,021,487	-	-	1	-	3,021,488
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 CASCADE NATURAL GAS CORPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2018

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, 2018

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	5,818,921			(1)		5,818,920
83	368	Compressor Station Equipment	-					-
84	369	Measuring and Regulating Station Equipment	36,161			1		36,162
85	370	Communications Equipment	-					-
86	371	Other Equipment	-					-
86.a	372	ARO - Transmission	24,974		(81)			24,893
87		TOTAL Transmission Plant	5,900,880	-	(81)	-	-	5,900,799
88		5. Distribution Plant						
89	374	Land and Land Rights	376,880	1,069				377,949
90	375	Structures and Improvements	363,785					363,785
91	376	Mains	92,660,285	9,432,904	(412,977)			101,680,212
92	377	Compressor Station Equipment	-					-
93	378	Measuring and Regulating Equipment - General	10,342,137	284,583	(20,886)			10,605,834
94	379	Measuring and Regulating Equipment - City Gate	-					-
95	380	Services	51,350,519	5,096,499	(162,067)	(1)		56,284,950
96	381	Meters	14,676,177	4,511,458	(2,711,038)	110,128		16,586,725
97	382	Meter Installations	9,108,506	567,179	(6,263)	1	(9,835)	9,659,588
98	383	House Regulators	2,706,169	236,336	(115,785)	20,307		2,847,027
99	384	House Regulator Installations	-					-
100	385	Industrial Measuring and Regulating Station Equipment	1,877,868	318,171	(5,976)		9,835	2,199,898
101	386	Other Property on Customers' Premises	-					-
102	387	Other Equipment	-					-
102.a	388	ARO - Distribution	4,359,610	478,686	(21,472)	10,719		4,827,543
103		TOTAL Distribution Plant	187,821,936	20,926,885	(3,456,464)	141,154	-	205,433,511

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, 2018

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	493,301					493,301
106	390	Structures and Improvements	4,503,032	13,144		(1)		4,516,175
107	391	Office Furniture and Equipment	182,715		(4,239)	1		178,477
108	392	Transportation Equipment	3,790,152	299,131	(337,134)			3,752,149
109	393	Stores Equipment	-					-
110	394	Tools, Shop and Garage Equipment	1,274,627	291,236	(26,312)		(21,109)	1,518,442
111	395	Laboratory Equipment	-					-
112	396	Power Operated Equipment	1,249,120	738,432	(734,509)		(28,518)	1,224,525
113	397	Communication Equipment	1,598,881	6,860				1,605,741
114	398	Miscellaneous Equipment	7,209					7,209
115		SUBTOTAL	13,099,037	1,348,803	(1,102,194)	-	(49,627)	13,296,019
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	13,099,037	1,348,803	(1,102,194)	-	(49,627)	13,296,019
118		TOTAL (Accounts 101 and 106)	209,843,340	22,275,688	(4,558,739)	141,155	(49,627)	227,651,817
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	209,843,340	22,275,688	(4,558,739)	141,155	(49,627)	227,651,817

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, 2018

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				
5				
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52	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, 2018

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	Replace 12" HP main in Bend, OR	1,304,280	
2			
3			
4			
5			
6	Minor installation of mains, service lines, measuring and regulating stations,	490,620	
7	meter sets and telemetering, and etc.		
8			
9			
10			
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43	T O T A L -	1,794,900	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, 2018

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	(96,626,376)	(96,626,376)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(5,979,861)	(5,979,861)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(278,751)	(278,751)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	(73,384)	(73,384)		
7.02	Other	-			
8		-			
9	TOTAL Depreciation Provisions for Year (Enter total of lines 3 thru 8)	(6,331,996)	(6,331,996)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	4,558,740	4,558,740		
12	Cost of Removal	1,076,256	1,076,256		
13	Salvage (credits)	(873,770)	(873,770)		
14	TOTAL Net Charges for Plant Retired (enter Total of Lines 11 thru 13)	4,761,226	4,761,226		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	(4,686)	(4,686)		
15.02	Adjustment Due to Transfers/Adjustments & Alloc. Rate Change	(34,290)	(34,290)		
16					
17	Balance End of Year (Enter Total of Lines 1, 9, 14, 15, & 16)	(98,236,122)	(98,236,122)		
	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	(3,628,864)	(3,628,864)		
25	Distribution	(91,161,934)	(91,161,934)		
26	General	(3,837,117)	(3,837,117)		
26.01	Intangible	(73,667)	(73,667)		
26.02	Retirement Work-In-Progress	465,460	465,460		
27	TOTAL (Enter Total of Lines 18 thru 26)	(98,236,122)	(98,236,122)		

NOTE:
Row 15.02 Other Debit or Credit due to transfer of assets, and related depreciation reserve between state jurisdictions

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, 2018

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)	14,274,775		14,274,775			
4	Property Under Capital Leases	-					
5	Plant Purchased or Sold	-					
6	Completed Construction not Classified	363,147		363,147			
7	Experimental Plant Unclassified	-					
8	TOTAL (Enter Total of lines 3 thru 7)	14,637,922	-	14,637,922	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	246,016		246,016			
12	Acquisition Adjustments	-					
13	Total Utility Plant (Lines 8 thru 12)	14,883,938	-	14,883,938	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(7,453,483)		(7,453,483)			
15	Net Utility Plant (Line 13 less 14)	7,430,455	-	7,430,455	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(3,158,996)		(3,158,996)			
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	(4,294,487)		(4,294,487)			
22	Total In-Service (Lines 18 thru 21)	(7,453,483)	-	(7,453,483)	-		-
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)	(7,453,483)	-	(7,453,483)	-		-

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, 2018

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	37,957			288		38,245
3	302	Franchises and Consents	-					-
4	303	Miscellaneous Intangible Plant	9,180,318	207,604		69,882		9,457,804
5		TOTAL Intangible Plant	9,218,275	207,604	-	70,170	-	9,496,049
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 CASCADE NATURAL GAS CORPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2018

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

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

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

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

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

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

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	23,687			180		23,867
90	375	Structures and Improvements	99,637			759		100,396
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	123,324	-	-	939	-	124,263

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, 2018

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	238,296			1,814		240,110
106	390	Structures and Improvements	1,472,134	11,777		11,207		1,495,118
107	391	Office Furniture and Equipment	1,768,014	119,569		13,457		1,901,040
108	392	Transportation Equipment	478,242	50,516	(18,499)	3,640	93	513,992
109	393	Stores Equipment	10,755			82		10,837
110	394	Tools, Shop, and Garage Equipment	475,421	135,417	(5,725)	3,619	5,309	614,041
111	395	Laboratory Equipment	24,181		(1,572)	185		22,794
112	396	Power Operated Equipment	(17,572)	3,871	(14,554)	(134)	4,070	(24,319)
113	397	Communication Equipment	224,919	2,406		1,712		229,037
114	398	Miscellaneous Equipment	14,847			113		14,960
115		SUBTOTAL	4,689,237	323,556	(40,350)	35,695	9,472	5,017,610
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	4,689,237	323,556	(40,350)	35,695	9,472	5,017,610
118		TOTAL (Accounts 101 and 106)	14,030,836	531,160	(40,350)	106,804	9,472	14,637,922
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	14,030,836	531,160	(40,350)	106,804	9,472	14,637,922

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, 2018

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	TOTALS -	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, 2018

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	No projects equal to or above $500,000		
2			
3	Other general plant work in progress expenditures	246,016	
4			
5			
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48	TOTAL -	246,016	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, 2018

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	(2,879,027)	(2,879,027)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(175,117)	(175,117)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(28,560)	(28,560)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	-	-		
7.02	Other	-			
8		-			
9	TOTAL Depreciation Provisions for Year (Enter total of lines 3 thru 8)	(203,677)	(203,677)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	40,350	40,350		
12	Cost of Removal	-	-		
13	Salvage (credits)	(8,285)	(8,285)		
14	TOTAL Net Charges for Plant Retired (enter Total of Lines 11 thru 13)	32,065	32,065		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	(86,465)	(86,465)		
15.02	Adjustment Due to Change in Allocation Rate	(21,892)	(21,892)		
16					
17	Balance End of Year (Enter Total of Lines 1, 9, 14, 15, & 16)	(3,158,996)	(3,158,996)		
	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	-	-		
25	Distribution	(105,349)	(105,349)		
26	General	(3,056,164)	(3,056,164)		
26.01	Intangible	-	-		
26.02	Retirement Work-In-Progress	2,517	2,517		
27	TOTAL (Total of Lines 18 thru 26)	(3,158,996)	(3,158,996)		

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

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, 2018

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)					
4	Gas withdrawn from storage					
5	(contra account)			$ 82,746		$ 82,746
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					21,999
31	Amount per Mcf					3.76
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	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

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, 2018

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	TOTAL		
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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, 2018

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
						10.80	7,404,220	$ 20,501,562	277	2
										3
								$ 477,857	n/a	4
										5
								$ 8,155,129	n/a	6
										7
							7,404,220	$ 29,134,548	n/a	8
										9
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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, 2018

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 r 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 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	4,787	$ 10,870	0	0	0
6	(Report separately for each principal use. Group minor uses).						
7							
8							
9							
10							
11							
12							
13							
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21							
22	TOTAL		4,787	$ 10,870			

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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, 2018

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		7,399,433
11	f. LNG		
12	g. Other		
13	TOTAL GAS PURCHASED		7,399,433
14	Gas of others received for transportation		22,534,732
15	Receipts of respondents' gas transported or compressed by others		
16	Exchange gas received		
17	Gas withdrawn from underground storage		168,436
18	Gas received from LNG storage		
19	Gas received from LNG processing		
20	Other receipts: (specify)		
21	TOTAL RECEIPTS		30,102,601

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, 2018

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		671,341
39	(ii) Other distribution system sales		6,914,346
40	TOTAL DISTRIBUTION SYSTEM SALES		7,585,687
41	d. Interdepartmental sales		
42	TOTAL SALES		7,585,687
43			
44	Deliveries of gas transported or compressed for:		
45	a. Other interstate pipeline companies		
46	b. Others		22,534,732
47	TOTAL, GAS TRANSPORTED OR COMPRESSED FOR OTHERS		22,534,732
48	Deliveries of respondent's gas for transportation or compression by others		
49	Exchange gas delivered		
50	Natural gas used by respondent		4,787
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		30,125,206
57	Production system losses		
58	Storage losses		
59	Transmission system losses		
60	Distribution system losses		(22,605)
61	Other losses (specify in so far as possible)		
62	TOTAL UNACCOUNTED FOR		(22,605)
63	TOTAL SALES, OTHER DELIVERIES & UNACCOUNTED FOR		30,102,601

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, 2018

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.	205,779	50,004	155,775
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)	324,569	81,629	242,940
6	Director's Fees (paid to MDU for CNGC's share of director's expenses)	363,054	91,308	271,746
7	Miscellaneous under $250,000			
8	2,725 items	278,017	74,555	203,462
9				
10				
	TOTAL	1,171,419	297,496	873,923

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, 2018

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, 2018

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	No on 1631 WA I-1631 was to be a Energy Tax on WA Consumers based upon carbon emissions.	426.4	12,575.00
	TOTAL		12,575.00

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, 2018

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	905,672	227,777
2	MDU/MDUR Allocated - approved in Order 07-418	426.1	6,147	1,546
3	MDU/MDUR Allocated - approved in Order 07-418	426.2	402,569	101,246
4	MDU/MDUR Allocated - approved in Order 07-418	426.4	799	201
5	MDU/MDUR Allocated - approved in Order 07-418	813	140,750	35,399
6	MDU/MDUR Allocated - approved in Order 07-418	875	100,806	25,353
7	MDU/MDUR Allocated - approved in Order 07-418	880	301,853	75,916
8	MDU/MDUR Allocated - approved in Order 07-418	901	42,213	10,617
9	MDU/MDUR Allocated - approved in Order 07-418	902	221,387	55,679
10	MDU/MDUR Allocated - approved in Order 07-418	903	5,258,124	1,322,418
11	MDU/MDUR Allocated - approved in Order 07-418	904	21,961	5,523
12	MDU/MDUR Allocated - approved in Order 07-418	909	11,362	2,857
13	MDU/MDUR Allocated - approved in Order 07-418	910	4,258	1,071
14	MDU/MDUR Allocated - approved in Order 07-418	913	3	1
15	MDU/MDUR Allocated - approved in Order 07-418	920	5,376,819	1,352,270
16	MDU/MDUR Allocated - approved in Order 07-418	921	3,026,367	761,131
17	MDU/MDUR Allocated - approved in Order 07-418	922	(158,954)	(39,977)
18	MDU/MDUR Allocated - approved in Order 07-418	923	252,617	63,533
19	MDU/MDUR Allocated - approved in Order 07-418	925	651	164
20	MDU/MDUR Allocated - approved in Order 07-418	926	19,269	4,846
21	MDU/MDUR Allocated - approved in Order 07-418	930.1	24,240	6,096
22	MDU/MDUR Allocated - approved in Order 07-418	930.2	388,951	97,821
23	MDU/MDUR Allocated - approved in Order 07-418	931	1,490,035	374,744
24	MDU/MDUR Allocated - approved in Order 07-418	932	45	11
25	Other Services	VAR	1,583,934	502,882
	TOTALS		19,421,878	4,989,125

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, 2018

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	CNG Contributions to Winter Help (WA and OR)	426.1	50,000	12,575
3	United Way (WA and OR)	426.1	1,954	866
4	Other Organizations (14 organizations)	426.1	7,423	3,476
5	Total contributions to and memberships in charitable organizations		59,377	16,917
6	(b) Organizations of the Utility Industry:			
7	American Gas Association (Washington D.C.)	426.4/930.2	115,221	28,978
8	Northwest Gas Association (West Linn, OR)	426.4/930.2	70,792	17,804
9	Western Energy Institute (Portland, OR)	921.0/930.2	10,351	2,603
10	North American Energy Standards Board (Houston, TX)	930.2	7,000	1,761
11	Other Organizations (3 organizations)	908.0/930.2/921.0	246	125
12	Total contributions to Organizations of the Utility Industry		203,610	51,271
13	(c) Technical and Professional Organizations			
14	National Association of Corrosion Engineers (Houston, TX)	921.0	2,000	503
15	Other Organizations (20 organizations)	921.0	4,442	1,117
16	Total contributions to Professional Organizations		6,442	1,620
17	(d) Commercial and Trade Organizations			
18	Association of Washington Business (Olympia, WA)	930.2/921.0	33,000	8,300
19	Chamber of Commerce-12 (OR)	426.4/921.0/930.2	12,500	3,892
20	Economic Development Councils-3 (OR)	426.1/930.2	46,977	14,380
21	Other Organizations (3 organizations)	426.1/908.0/930.2	3,086	1,124
22	Total contributions to Commercial and Trade Organizations		95,563	27,696
23	(e) Other Organizations & Donations			
24	MDU Resources expenses (Bismark, ND)	426.1/426.4/921.0	22,061	5,548
25	Grandridge Business Park (Kennewick WA)	930.2	7,837	1,971
26	Other Organizations	426.1921.0/930.2	10,000	2,515
27	Total Other Organizations		39,898	10,034
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
	TOTAL		435,701	123,117

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, 2018

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/	Nicole A. Kivisto	4/	
2	Chairman of the Board 2/	David L. Goodin	4/	
3	Executive VP-Bus Development & Gas Supply 1/	Scott W. Madison	4/	
4	VP Field Operations 1/	Eric P. Martuscelli	4/	
5	VP-Regulatory Affairs & Cust Service 1/	Mark A. Chiles	4/	
6	VP-Human Resources 2/	Anne M. Jones	4/	
7	Assistant Secretary 2/	Julie A. Krenz	4/	
8	General Counsel and Secretary 2/	Daniel S. Kuntz	4/	
9	Assistant Secretary 2/	Karl A. Liepitz	4/	
10	Treasurer 2/	Jason L. Vollmer	4/	
11	Executive VP -Reg Affairs, Cust Service & Administration 1/	Garret Senger	4/	
12	Controller 1/	Tammy J. Nygard	4/	
13	Chief Information Officer 2/	Margaret (Peggy) A. Link	4/	
14	VP-Engineering & Operations Services 1/	Patrick C. Darras	4/	
15	VP-Safety, Process Improvement & Operating Systems 1/	Hart Gilchrist	4/	
16				
17				
18	1/ Salary includes amount allocated to CNGC from MDU			
19	2/ Salary includes amount allocated to CNGC from MDUR			
20	4/ Confidential salary data included on filed reports with OPUC.			
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, 2018

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 RECIPENT (a)	NATURE OF SERVICE (b)	AMOUNT OF PAYMENT (c)
1	Black & Veatch	Consulting	184,299
2	Heath Consultants, Inc	Construction	176,270
3	McDowell Rackner & Gibson, PC	Consulting	129,103
4	ABI Services, LLC	Construction	114,366
5	Deloitte & Touche, LLP	Audit	70,919
6	Parametrix, Inc.	Construction	66,689
7	Anchor QEA	Consulting	63,039
8	Big Schatz Construction	Construction	41,702
9	Veris Law Group, PLLC	Legal	39,049
10	Northwest Metal Fab & Pipe, Inc.	Construction	38,742
11	Garvey Schubert Barer	Legal	38,184
12	Mears Group, Inc.	Construction	37,483
13	Knife River-Western OR Division	Construction	35,427
14	Bend Heating	Construction	34,786
15	One Call Concepts, Inc	Construction	26,714
16	Evergreen Financial Services	Collection	25,506
17	Other		484,868
18			
19			
20			
21			
22			
23			
24			
25			
	TOTAL		1,607,146

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, 2018

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

Oregon Production Statistics (therms)	
Gas Produced	
Gas Purchased	325,135,519
Total Receipts	325,135,519

Gas Sales	325,327,969
Gas used by Company	51,702
Gas Delivered to LNG Storage - Net	
Losses & Billing Delay	(244,152)
Total Disbursements	325,135,519

Oregon Revenue by Service Class	
Residential	$ 35,735,955
Commercial & Industrial	$ 23,799,507
Firm	
Interruptible	
Transportation	$ 4,125,679
Total	$ 63,661,141

Gas Sold in Therms (Oregon)	
Residential	44,047,108
Commercial & Industrial	37,885,223
Firm	
Interruptible	
Transportation	243,395,638
Total	325,327,969

Average Number of Customers	
Residential	64,137
Commercial & Industrial	10,218
Firm	
Interruptible	
Transportation	36
Total	74,391

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Cascade Natural Gas Corporation	(1)An Original (2)A Resubmission	(Mo, Da, Yr)	End of Dec. 31, 2018

Distribution of Salaries and Wages
Oregon Jurisdiction

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	3,287,799			3,287,799
34	Customer Accounts	1,047,262			1,047,262
35	Customer Service and Informational	191,875			191,875
36	Sales	-			-
37	Administrative and General	1,455,735			1,455,735
38	TOTAL Operation (Total of lines 28 thru 37)	5,982,671	-	-	5,982,671
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	1,095,150			1,095,150
46	Administrative and General				
47	TOTAL Maintenance (Total of lines 40 thru 46)	1,095,150	-	-	1,095,150
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)	4,382,949			4,382,949
56	Customer Accounts (Total of line 34)	1,047,262			1,047,262
57	Customer Service and Informational (Total of line 35)	191,875			191,875
58	Sales (Total of line 36)	-			-
59	Administrative and General (Total of lines 37 and 46)	1,455,735			1,455,735
60	Total Operation and Maintenance (Total of lines 50 thru 59)	7,077,821	-	-	7,077,821
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	7,077,821	-	-	7,077,821
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	2,045,219			2,045,219
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	2,045,219	-	-	2,045,219
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	54,569			54,569
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	54,569	-	-	54,569
75	PTO/Incentive/Severance Pay Liabilities	247,107			247,107
76	TOTAL Other Accounts	247,107	-	-	247,107
77	TOTAL SALARIES AND WAGES	9,424,716	-	-	9,424,716

MDU Resources Group, Inc.

Building a Strong America®

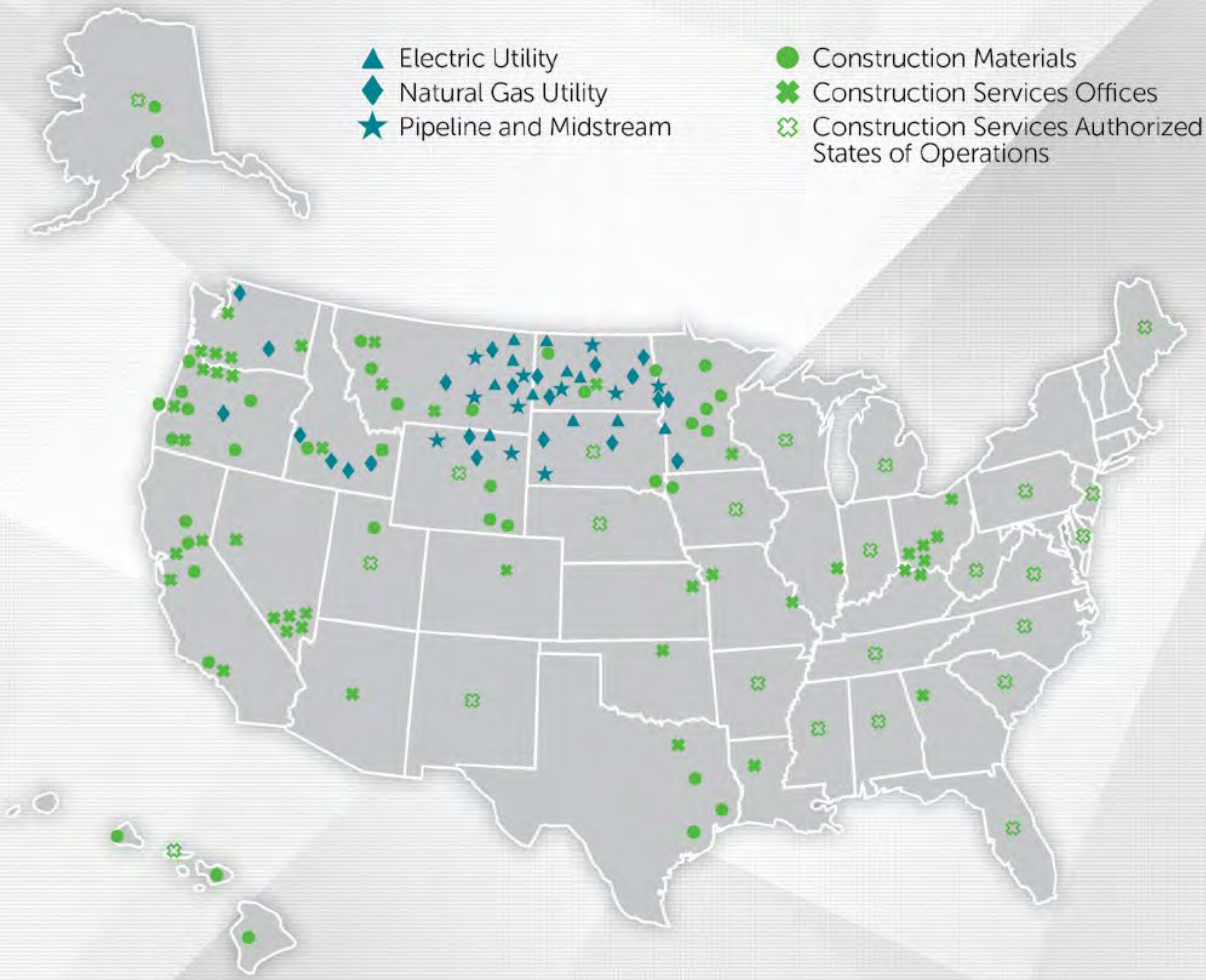
Annual Report
—
Form 10-K
—
Proxy Statement

2018

MDU RESOURCES
GROUP, INC.

MDU RESOURCES
GROUP, INC.
Building a Strong America®

2018



MDU Resources Group, Inc. is a member of the S&P MidCap 400 index and the S&P High-Yield Dividend Aristocrats index. We are Building a Strong America® by providing essential products and services through our regulated energy delivery and construction materials and services businesses.

MDU
LISTED
NYSE

Conducting business in 44 states

11,797 employees

1.8 Bcf/day of natural gas pipeline capacity

1.1 million utility customers

11th largest specialty contractor, according to Engineering News-Record

1 billion tons of aggregate reserves

2018 annual dividend per share: **80** cents

Paid dividends **81** consecutive years

Increased dividends **28** consecutive years

2018 earnings: $269.4 million / $1.38 EPS, from continuing operations

MDU RESOURCES GROUP, INC

Building a Strong America®

At December 31, 2018.

Highlights

Years ended December 31,	2018	2017
	(In millions, where applicable)	
Operating revenues	$4,531.6	$4,443.4
Operating income	$ 401.7	$ 424.1
Earnings on common stock from continuing operations	$ 269.4	$ 284.2
Earnings on common stock, including discontinued operations	$ 272.3	$ 280.4
Earnings per common share from continuing operations	$ 1.38	$ 1.45
Earnings per common share, including discontinued operations	$ 1.39	$ 1.43
Dividends declared per common share	$ .795	$ .775
Weighted average common shares outstanding — diluted	196.1	195.7
Total assets	$ 6,988	$ 6,335
Total equity	$ 2,567	$ 2,429
Total debt	$ 2,109	$ 1,715
Capitalization ratios:		
Total equity	54.9%	58.6%
Total debt	45.1	41.4
	100%	100%
Price/earnings from continuing operations ratio (12 months ended)	17.3x	18.5x
Book value per common share	$ 13.09	$ 12.44
Market value as a percent of book value	182.1%	216.1%
Employees	11,797	10,140

Forward-looking statements: This Annual Report contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements are all statements other than statements of historic fact, including without limitation those statements that are identi ed by the words anticipates, estimates, expects, intends, plans, predicts and similar expressions. Forward-looking statements should be read with, and are subject to, the cautionary statements and important factors included in “Part I, Forward-Looking Statements” and “Item 1A — Risk Factors” of the company’s “2018 Form 10-K.”

Our Businesses

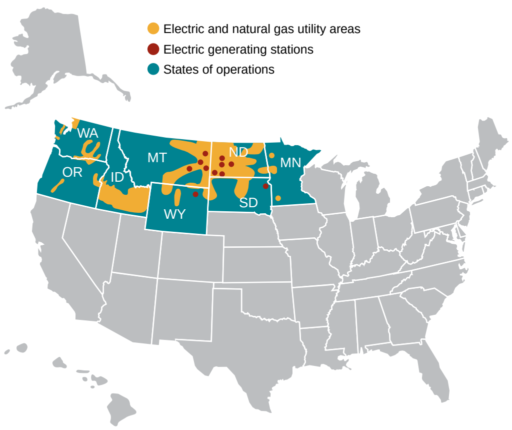
Regulated Energy Delivery

Electric and Natural Gas Utilities

MDU Resources Group's utility companies serve approximately 1.1 million customers. Cascade Natural Gas Corporation distributes natural gas in Oregon and Washington. Great Plains Natural Gas Co. distributes natural gas in western Minnesota and southeastern North Dakota. Intermountain Gas Company distributes natural gas in southern Idaho. Montana-Dakota Utilities Co. generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. These operations also supply related value-added services.

2018 Key Statistics

Revenues (millions)	
Electric	$335.1
Natural gas	$823.2
Earnings (millions)	
Electric	$47.0
Natural gas	$37.7
Electric retail sales (million kWh)	3,354.4
Natural gas distribution (MMdk)	
Sales	112.6
Transportation	149.5



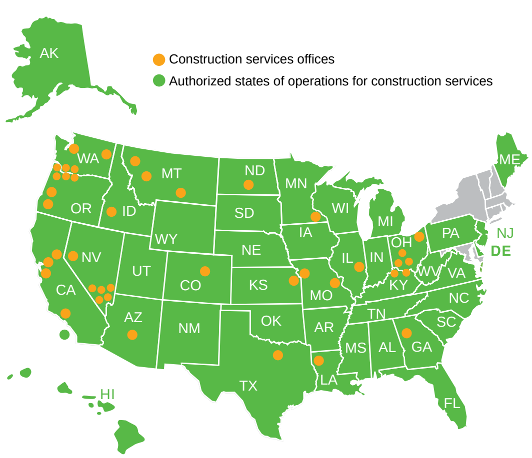
Construction Materials and Services

Construction Services

MDU Construction Services Group provides inside and outside specialty contracting services, including constructing and maintaining electric and communication lines, gas pipelines, re suppression systems, and external lighting and traf c signalization. It also provides utility excavation and inside electrical and mechanical services, and manufactures and distributes transmission line construction equipment and supplies.

2018 Key Statistics

Revenues (millions)	$1,371.5
Earnings (millions)	$64.3



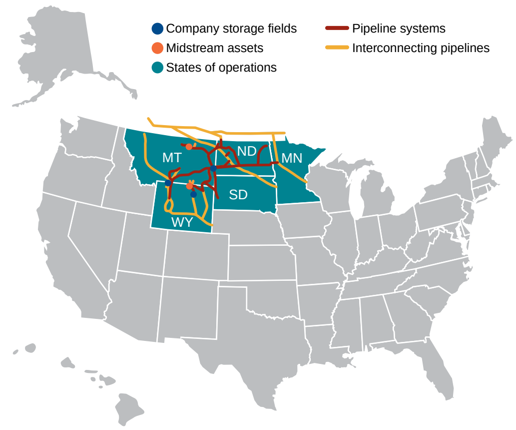
Regulated Energy Delivery

Pipeline and Energy Services

WBI Energy provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems, primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment also provides cathodic protection and other energy-related services.

2018 Key Statistics

Revenues (millions)	$128.9
Earnings (millions)	$28.5
Pipeline (MMdk)	
Transportation	351.5
Gathering	14.9



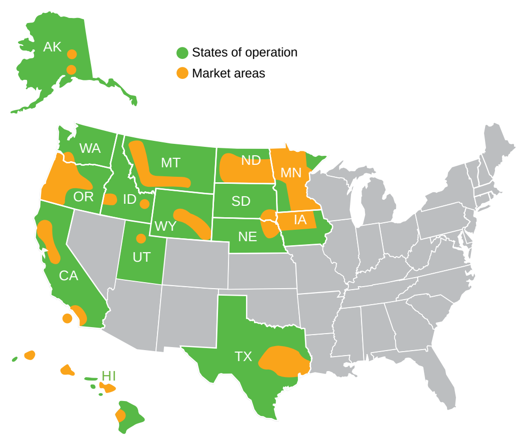
Construction Materials and Services

Construction Materials and Contracting

Knife River Corporation mines aggregates and markets crushed stone, sand, gravel ar related construction materials, including ready-mix concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated contracting service

2018 Key Statistics

Revenues (millions)	$1,925.9
Earnings (millions)	$92.6
Construction materials sales (thousands)	
Aggregates (tons)	29,795
Asphalt (tons)	6,838
Ready-mix concrete (cubic yards)	3,518
Construction materials aggregate reserves (billion tons)	1.0



Note: The revenues and earnings noted on this page exclude discontinued operations, the Other category and intercompany eliminations.

Report to Stockholders

Our operations performed very well in 2018, successfully executing on growth projects and managing costs while meeting customers' needs. We are pleased with our strong results, which continue to reflect the advantage of our two-pillar strategy of growing our regulated energy delivery businesses through organic projects while growing our construction materials and services market share through strong customer relationships and acquisitions.

Earnings in 2018 from continuing operations were $269.4 million, or $1.38 per share, compared to 2017 earnings from continuing operations of $284.2 million, or $1.45 per share. Including discontinued operations, MDU Resources reported 2018 earnings of $272.3 million, or $1.39 per share, compared to $280.4 million, or $1.43 cents per share, in 2017. The company recorded a benefit in 2017 of $39.5 million, or 20 cents per share, attributable to the federal Tax Cuts and Jobs Act. Absent the benefit from tax reform, our earnings from continuing operations were up 13 cents per share year over year, or approximately 10 percent.

Our employees remain dedicated to Building a Strong America,® providing essential products and services to the American people. We provide the natural gas and electricity that power business, industry and our daily lives. We connect homes, factories, offices and stores with the pipes and wires that bring them to life. We build the transportation network of roads, highways and airports that keeps our economy moving. The heart of our American economy is infrastructure, and infrastructure is our business.

We expect 2019 to be another strong year, starting off with a record backlog of projects at both our construction businesses, significant growth projects at our natural gas pipeline company and planned capital infrastructure investments at our utility operations. We expect to invest $579 million in capital projects this year, with $2.6 billion in planned investments over the next five years. We are confident our company will continue to provide the long-term returns you expect.

Construction services breaks records

The construction services business had outstanding results in 2018, with record revenues, earnings and backlog. Earnings were $64.3 million, which is 21 percent higher than earnings of $53.3 million in 2017. This is even more impressive when you consider that 2017 results included a $4.3 million benefit from tax reform. We had record year-end backlog of $939 million, up 33 percent compared to $708 million in 2017.

We saw higher workloads and margins in 2018 in our outside specialty electrical contracting work, particularly power line and substation projects and recovery work for utilities that were impacted by weather events and natural disasters. We also continued in 2018 to see strong demand for sales and rentals of the utility construction equipment we manufacture.

We have a high volume of inside specialty electrical and mechanical contracting work in our backlog, particularly for customers in the high-tech, manufacturing and hospitality industries. Our strong execution on these types of projects often gives us the opportunity for repeat business from customers who value our top-quality design and build services.

We are the 11th largest specialty contractor in the U.S., according to Engineering News Record's "2018 Top 600 Specialty Contractors" list, and we have more than 5,500 skilled employees working across 43 states for this business. We are exploring acquisition opportunities to further grow our market share in construction services.

Construction materials has record backlog

Our construction materials business earned $92.6 million in 2018, compared to $123.4 million in 2017. Earnings in 2017 included a $41.9 million benefit from federal tax reform. Like our construction services business, our construction materials business ended the year with record backlog. At December 31, backlog was $706 million, a 45 percent increase from the same time in 2017.

The geographic diversity of our operations continues to be a benefit, as we saw strong construction demand in some markets but weaker demand in others, including impacts from the recession in Alaska, above-average precipitation in Texas and weather in the Midwest. Our operations in California are located near the area impacted by a devastating 2018 fire. While our facilities were spared, some of our employees lost everything and we continue assisting those impacted while working with the communities on restoration efforts.

We acquired four construction materials operations in 2018. In April, we acquired Teevin & Fischer Quarry LLC, a leading aggregate producer serving customers in the area of Clatsop County, Oregon. In June, we acquired Tri-City Paving Inc., a general contractor and aggregate, asphalt and ready-mix concrete supplier headquartered in Little Falls, Minnesota. In July, we added Molalla Redi-Mix and Rock Products Inc., a ready-mix concrete producer in Molalla, Oregon, near Portland. In October, we acquired Sweetman Const. Co., a premier provider of aggregates, asphalt and ready-mix concrete in the Sioux Falls, South Dakota, market. We expect to continue our acquisition strategy this year.

We have strong momentum going into 2019 with our record backlog of projects, and we continue to see strong bidding opportunities in markets with robust economies. With state and federal officials

Harry J. Pearce
Chair of the Board

David L. Goodin
President and Chief Executive O cer

focused on the growing need for infrastructure repairs and replacements across our country, we are well-positioned with our more than 1 billion tons of aggregate reserves to take on additional work.

Pipeline transports record volume

Our pipeline and midstream business earned $28.5 million in 2018, compared to $20.5 million in 2017. Results in 2018 included a $4.2 million tax bene t related to a nal accounting order by the Federal Energy Regulatory Commission, and results in 2017 included a $200,000 decrease related to federal tax reform.

Our pipeline business in 2018 transported a record volume of natural gas for the second year in a row, approximately 12 percent more than in 2017. is is partly due to continuing to expand our pipeline system through organic growth projects. We completed in September our Line Section 27 expansion in northwestern North Dakota and in November our Valley Expansion Project in eastern North Dakota and far western Minnesota. ese projects increased our system capacity by more than 240 million cubic feet per day, bringing total capacity to more than 1.8 billion cubic feet per day.

We continue to see great need for natural gas pipeline capacity in the Bakken region as our customers face increasing aring restrictions while growing their natural gas production to record volumes, generally month over month. We will begin construction this spring on two additional expansion projects. e Demicks Lake project will be constructed in McKenzie County, North Dakota, and will add approximately 175 million cubic feet per day of capacity. Line Section 22 is an expansion project near Billings, Montana, adding approximately 22.5 million cubic feet per day of capacity. We expect both projects to be complete late this year.

We also recently announced the North Bakken Expansion Project, which as planned is a 67-mile, 20-inch pipeline that will start at our existing compressor station near Tioga, North Dakota, and end at a new interconnection point with Northern Border Pipeline in McKenzie County. e project is designed to provide 200 million cubic feet per day of additional natural gas capacity, but it can be expanded to provide up to 375 million cubic feet per day depending on customer demand. Pending regulatory and environmental approvals, we anticipate constructing this project in 2021.

We are planning additional future projects to help our customers capture and deliver to market more Bakken natural gas, of which at year-end approximately 20 percent was being ared, and we look forward to telling you more about these projects as they come to fruition.

We have a rate case pending before the FERC, which our pipeline business led on October 31 in accordance with a settlement agreement reached in 2014 with customers and the FERC. e FERC has set a procedural schedule for the case and proposed rates will take e ect May 1, 2019, subject to refund and the outcome of a hearing established in the case.

Utility customer base continues to grow

Our electric and natural gas utility business earned $84.7 million, compared to $81.6 million in 2017. e 2017 results include a decrease of $6.4 million from federal tax reform. Our utility operations led rate adjustments in every jurisdiction to return to customers the bene ts of lower federal income taxes. We have implemented rates that provide $25 million in annual reductions to our customers.

Our utility customer base continued to grow in 2018, up approximately 1.8 percent. We expect to see our 1.1 million customer base continue to increase at a rate of 1 to 2 percent each year. Electric sales volumes in 2018 increased 1.4 percent while natural gas sales were virtually unchanged from 2017.

We nalized in the fourth quarter our purchase of an expansion of the under Spirit Wind farm in southwest North Dakota for $84 million e expansion brought the total production capacity at that wind farm to approximately 155 megawatts. Including our other wind farm locations, our electric generation portfolio is now approximately 27 percent renewables.

In late 2018, we extended natural gas service to a manufacturing facility at Gwinner, North Dakota. As a result of this system expansion, we recently announced that we also will be extending natural gas service to residential and business customers in Gwinner and the nearby town of Milnor, North Dakota.

On February 5, 2019, the Big Stone-South-to-Ellendale 345-kilovolt transmission line, which we constructed with a partner, was put into service. We invested approximately $130 million in this Midcontinent Independent System Operator-approved project, which runs from Big Stone City, South Dakota, to Ellendale, North Dakota.

We announced February 19, 2019, that we plan to construct a new simple-cycle electric generation facility and retire our smaller, solely owned coal- red electric generation facilities. Our integrated resource planning process indicates that operating these aging coal- red plants, which were built in 1954 and 1958, is no longer the least-cost option for electricity for our customers. We anticipate closing our Lewis & Clark Station at Sidney, Montana, with a capacity of 44 MW, around the end of 2020, and our Heskett 1 and 2 plants at Mandan, North Dakota, with combined capacity of 100 MW, around the end of 2021. Upon regulatory approval, we expect to build an 88-MW natural gas- red peaking unit at our existing Heskett Plant site in Mandan.

We continue to invest in upgrading and expanding our electric and natural gas utility systems to safely and reliably meet customer demand, and we continue to pursue cost recovery of these investments through regulatory relief. We expect our rate base in the next ve years to continue growing 5 percent annually on a compound basis.

Sustainability a strong focus

While we have been publishing a sustainability report since 2008, our Board of Directors is sharpening its focus on sustainability-related e orts within the corporation. We are adapting our environmental, social and governance reporting to follow the standards outlined by the federal Sustainability Accounting Standards Board or other industry organizations for each of our companies' industries. We expect it will take some time to fully incorporate this e ort across our businesses, but we are committed to providing additional ESG information to our shareholders.

Related to ensuring our operations are sustainable, we constantly evaluate and mitigate potential risks. We have emphasized cybersecurity measures in the past several years to protect our internal systems, proprietary data and customer information from nefarious actors who might seek to harm our company. We are con dent our cybersecurity e orts are some of the best in the industry, and this has been con rmed by third-party experts. However, we know we can never rest on our laurels because hackers are always knocking at our virtual door.

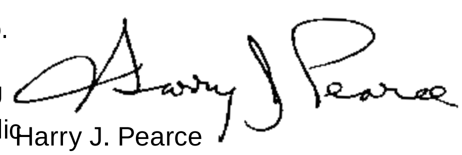
Beyond cybersecurity, we also evaluate and mitigate risks related to the physical security of our assets. A good portion of our business facilities are considered "critical infrastructure" by federal and state agencies because these facilities provide customers with critical services, such as electricity and natural gas, and means of transportation. We work to ensure these assets are protected from potential physical breaches and damage, and we have in place emergency response plans to recover from any such disasters.

We completed at the start of 2019 a holding company reorganization that further delineates the separation between our corporation and our utility companies. Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. were originally structured as divisions of MDU Resources, per requirements of the Public Utility Holding Company Act of 1935. e Energy Policy Act of 2005 repealed the PUHCA and allowed us to restructure these companies as subsidiaries — Montana-Dakota Utilities is now a subsidiary of MDU Resources and Great Plains Natural Gas is a division of Montana-Dakota Utilities. e reorganization clari es our corporate structure and already has resulted in greater exibility in nancing options.

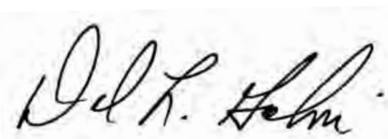
A er 22 years serving as a director on MDU Resources' board, nearly 14 of them as chair, Harry Pearce will not seek re-election at this year's Annual Meeting. William McCracken also will not stand for re-election, and Bart Holaday ended his term with the board in May 2018. Each of these directors reached the mandatory retirement age, per our company bylaws. We want to assure you that we have solid succession plans in place to ll key positions on the board. We added two directors, Edward Ryan and David Sparby, in the past year and have a third new director candidate standing for election at our Annual Meeting in May. is will help ensure a smooth transition of leadership. ese new directors bring substantial governance, merger-and-acquisition, nancial, regulated utility and cybersecurity experience to the board, as well as other important expertise.

 e board remains committed to paying a competitive dividend to shareholders and will continue to focus on providing you with the long-term returns you expect from MDU Resources.

We, with all MDU Resources' hardworking employees, look forward to continuing to provide the essential energy and construction products and services that are Building a Strong America.® ank you for your continued investment in our company.



Harry J. Pearce
Chair of the Board



David L. Goodin
President and Chief Executive O cer

February 22, 2019

Board of Directors

Harry J. Pearce
76 (22)
Detroit, Michigan

Chair of MDU Resources Board of Directors

Retired, formerly chair of Hughes Electronics Corp., a subsidiary of General Motors Corp., and former vice chair and director of GM; on the board of several organizations.

Expertise:Multinational business management, leadership, nance, engineering and law.

David L. Goodin
57 (6)
Bismarck, North Dakota

President and Chief Executive O cer of MDU Resources

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

Thomas Everist
69 (24)
Sioux Falls, South Dakota

President and chair of e Everist Co., formerly a construction materials company; a director of several corporations.

Expertise:Business management, construction and sand, gravel and aggregate production.

Karen B. Fagg
65 (14)
Billings, Montana

Retired, formerly vice president of DOWL HKM and formerly chair, chief executive o cer and majority owner of HKM Engineering Inc.; on the board of several organizations.

Expertise:Engineering, construction and business management.

Mark A. Hellerstein
66 (6)
Denver, Colorado

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

Expertise:Energy industry, business management, accounting and nance.

Dennis W. Johnson
69 (18)
Dickinson, North Dakota

Vice Chair of MDU Resources Board of Directors

Chair, president and chief executive o cer of TMI Corp., an architectural woodwork manufacturer; former president of the Dickinson City Commission; a former director of Federal Reserve Bank of Minneapolis.

Expertise:Business management, engineering and nance.

William E. McCracken
76 (6)
Warren, New Jersey

Retired, formerly chair and chief executive o cer of CA Technologies; previously held executive positions with IBM Corp.; on the board of several organizations; a former director of IKON O ce Solutions Inc.

Expertise:Multinational business management, corporate governance, technology and cybersecurity.

Patricia L. Moss
65 (16)
Bend, Oregon

Formerly vice chair, president and chief executive o cer of Cascade Bancorp and Bank of the Cascades; a director of First Interstate BancSystem Inc.

Expertise:Finance, banking, business development and human resources.

Edward A. Ryan
65 (1)
Washington, D.C.

Formerly executive vice president and general counsel of Marriott International.

Expertise:Leadership, corporate governance and law.

David M. Sparby
64 (1)
Minneapolis, Minnesota

Formerly senior vice president and group president, Revenue at Xcel Energy Inc. and president and chief executive o cer of Northern States Power-Minnesota.

Expertise:Public utilities, business management, nance and law.

John K. Wilson
64 (16)
Omaha, Nebraska

Formerly president of Durham Resources LLC, a privately held nancial management company, and formerly a director of a mutual fund; on the board of several organizations.

Expertise:Public utilities, accounting and nance.

Audit Committee
Dennis W. Johnson, Chair
Mark A. Hellerstein
Edward A. Ryan
David M. Sparby
John K. Wilson

Compensation Committee
 omas Everist, Chair
Karen B. Fagg
William E. McCracken
Patricia L. Moss

Nominating and Governance Committee
Karen B. Fagg, Chair
Dennis W. Johnson
William E. McCracken
Patricia L. Moss
Edward A. Ryan

Director Changes
A. Bart Holaday did not stand for re-election in 2018. His term as a director concluded May 8, 2018.

David M. Sparby was appointed to the Board of Directors on August 16, 2018.

Edward A. Ryan was appointed to the Board of Directors on November 15, 2018.

Numbers indicate age and years of service ( ) on the MDU Resources Board of Directors as of December 31, 2018.

Corporate Management

David L. Goodin
57 (36)

President and Chief Executive O cer of MDU Resources

Serves on the company's Board of Directors and as chair of the board of all major subsidiary companies; formerly president and chief executive o cer of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

David C. Barney
63 (33)

President and Chief Executive O cer of Knife River Corporation

Formerly held executive and management positions with Knife River.

Trevor J. Hastings
45 (23)

President and Chief Executive O cer of WBI Holdings, Inc.

Formerly vice president of business development and operations support of Knife River Corporation.

Anne M. Jones
55 (37)

Vice President of Human Resources of MDU Resources

Formerly vice president of human resources, customer service and safety of Cascade Natural Gas Corporation, Great Plains Natural Gas Co., Intermountain Gas Company and Montana-Dakota Utilities Co.

Nicole A. Kivisto
45 (24)

President and Chief Executive O cer of Cascade Natural Gas Corporation, Intermountain Gas Company and Montana-Dakota Utilities Co.

Formerly vice president of operations of Great Plains Natural Gas Co. and Montana-Dakota Utilities.

Daniel S. Kuntz
65 (15)

Vice President, General Counsel and Secretary of MDU Resources

Serves as general counsel and secretary of all major subsidiary companies; formerly associate general counsel and assistant secretary of MDU Resources.

Peggy A. Link
52 (14)

Vice President and Chief Information O cer of MDU Resources

Formerly assistant vice president of technology and cybersecurity o cer of MDU Resources.

Jeffrey S. Thiede
56 (15)

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

Formerly held executive and management positions with MDU Construction Services Group.

Jason L. Vollmer
41 (14)

Vice President, Chief Financial O cer and Treasurer of MDU Resources

Formerly vice president, chief accounting o cer and treasurer of MDU Resources.

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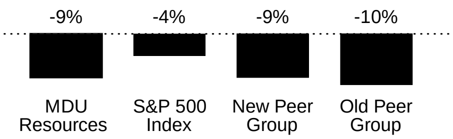
Stephanie A. Barth, 46 (23)
Vice President, Chief Accounting O cer and Controller of MDU Resources

Numbers indicate age and years of service ( ) as of December 31, 2018.

Stockholder Return Comparison

Comparison of One-Year Total Stockholder Return

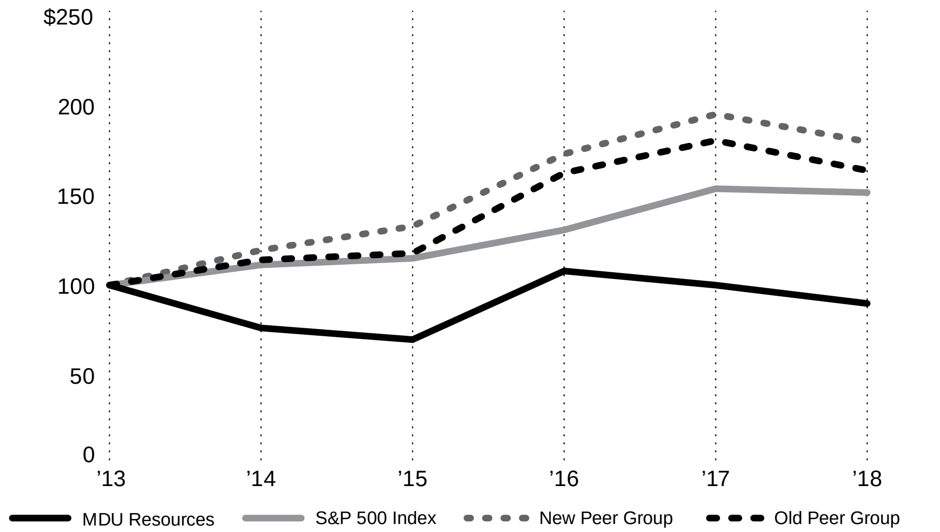
(as of December 31, 2018)



An explanation of the peer group is provided on the following page.

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

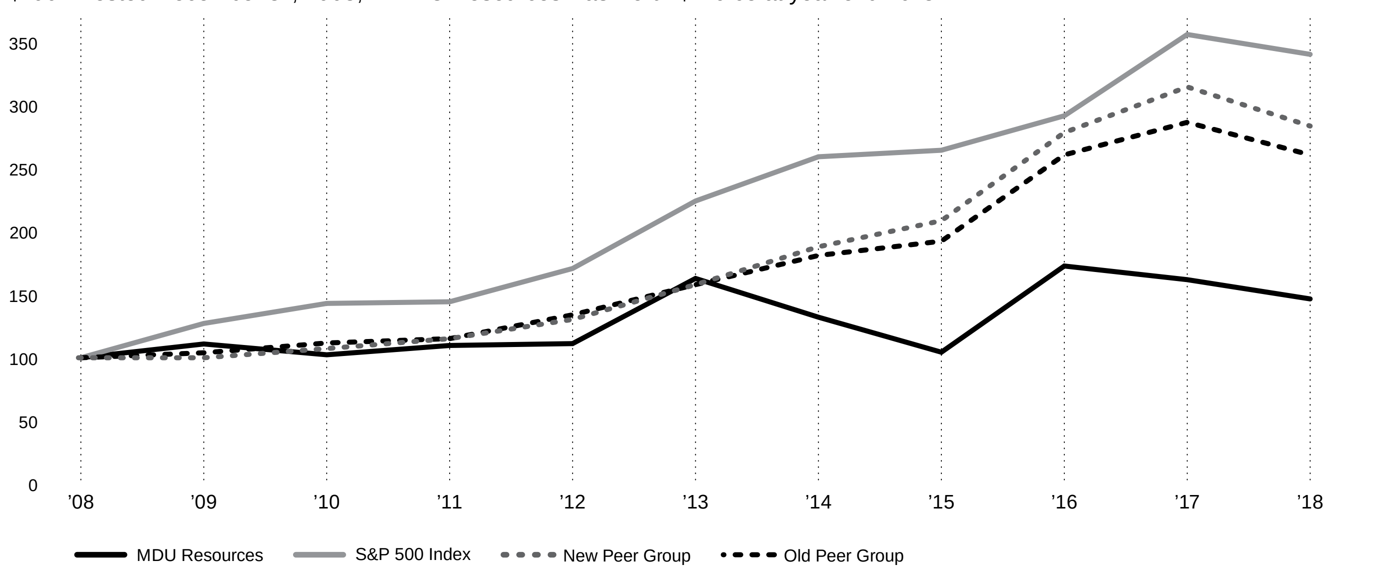
$100 invested December 31, 2013, in MDU Resources was worth $90.96 at year-end 2018.



	2013	2014	2015	2016	2017	2018
MDU Resources Group, Inc.	$100.00	$78.82	$63.86	$103.48	$99.53	$90.96
S&P 500 Index	100.00	113.69	115.26	129.05	157.22	150.33
New Peer Group	100.00	117.17	129.51	174.67	194.61	176.51
Old Peer Group	100.00	114.03	119.67	162.14	179.12	161.71

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

$100 invested December 31, 2008, in MDU Resources was worth $149.65 at year-end 2018.



	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
MDU Resources Group, Inc	$100.00	$112.89	$100.09	$109.25	$111.51	$164.53	$129.67	$105.06	$170.25	$163.76	$149.65
S&P 500 Index	100.00	126.46	145.51	148.59	172.37	228.19	259.43	263.02	294.48	358.77	343.04
New Peer Group	100.00	100.04	107.41	115.00	132.56	161.51	189.24	209.17	282.10	314.31	285.08
Old Peer Group	100.00	104.86	112.65	116.17	131.75	161.29	183.93	193.01	261.52	288.91	260.83

Stockholder Return Comparison

Data is indexed to December 31, 2017, for the one-year total stockholder return comparison, December 31, 2013, for the ve-year total stockholder return comparison and December 31, 2008, for the 10-year total stockholder return comparison for MDU Resources, the S&P 500 and the peer groups. 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.

E ective January 1, 2018, a new peer group was established. is change was made to better re ect the makeup of the company relative to each business segment's size and nature of business. e charts show stockholder return performance for both the old and new peer groups.

e new peer group issuers are ALLETE, Inc., Alliant Energy Corporation, Atmos Energy Corporation, Black Hills Corporation, EMCOR Group, Inc., Granite Construction Incorporated, IDACORP, Inc., Martin Marietta Materials, Inc., MasTec, Inc., MYR Group Inc., Northwest Natural Holding Company (formerly Northwest Natural Gas Company), NorthWestern Corporation, Otter Tail Corporation, Portland General Electric Company, Spire Inc., Southwest Gas Holding, Inc., Summit Materials, Inc., U.S. Concrete, Inc., Vectren Corporation and Vulcan Materials Company.

e old peer group issuers were ALLETE, Inc., Alliant Energy Corporation, Atmos Energy Corporation, Avista Corporation, Black Hills Corporation, EMCOR Group, Inc., Granite Construction Incorporated, IDACORP, Inc., IES Holdings, Inc., Martin Marietta Materials, Inc., MYR Group Inc., National Fuel Gas Company, Northwest Natural Gas Company, NorthWestern Corporation, Quanta Services, Inc., Sterling Construction Company, Inc., U.S. Concrete, Inc., Vectren Corporation and Vulcan Materials Company.

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, 2018

OR

o 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 1-03480

MDU RESOURCES GROUP, INC.

(Exact name of registrant as specified in its charter)

Delaware	30-1133956
(State or other jurisdiction of incorporation or€organization)	(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: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule€405 of the Securities Act. Yes€ No o.

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 o 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 o.

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule€405 of Regulation S-T (• 232.405 of this chapter) during the preceding 12€months (or for such shorter period that the registrant was required to submit such files). Yes€ No o.

Indicate by check mark if disclosure of delinquent filers pursuant to Item€405 of Regulation S-K (• 229.405 of this chapter) 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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule€12b-2 of the Exchange Act.

Large accelerated filer €	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o
	Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act o

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

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June€29, 2018 : $5,621,805,532 .

Indicate the number of shares outstanding of the registrant's common stock, as of February€14, 2019: 196,092,274 €shares.

DOCUMENTS INCORPORATED BY REFERENCE
Relevant portions of the registrant's 2019 Proxy Statement, to be filed no later than 120 days from December€31, 2018, are incorporated by reference in Part€III, Items€10, 11, 12, 13 and 14 of this Report.

Contents

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
ASU	FASB Accounting Standards Update
Audit Committee	Audit Committee of the board of directors of the Company
Bcf	Billion cubic feet
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7€percent ownership)
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines in Brazil
BSSE	345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota
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
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's Consolidated EBITDA	Centennial's consolidated net income from continuing operations plus the related interest expense, taxes, depreciation, depletion, amortization of intangibles and any non-cash charge relating to asset impairment for the preceding 12-month period
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
Company	MDU Resources Group, Inc. (formerly known as MDUR Newco), which, as the context requires, refers to the previous MDU Resources Group, Inc. prior to January 1, 2019, and the new holding company of the same name after January 1, 2019
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)
CyROC	Cyber Risk Oversight Committee
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company previously owned by WBI Energy and Calumet (previously included in the Company's refining segment)
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
EIN	Employer Identification Number
EPA	United States Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
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 (previously referred to as the Company's exploration and production segment)
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 prior to the closing of the Holding Company Reorganization and a public utility division of Montana-Dakota as of January 1, 2019
GVTC	Generation Verification Test Capacity

Holding Company Reorganization	The internal holding company reorganization completed on January 1, 2019, pursuant to the agreement and plan of merger, dated as of December 31, 2018, by and among Montana-Dakota, the Company and MDUR Newco Sub, which resulted in the Company becoming a holding company and owning all of the outstanding capital stock of Montana-Dakota.
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
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
LWG	Lower Willamette Group
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand dk
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
MDUR Newco	MDUR Newco, Inc., a public holding company created by implementing the Holding Company Reorganization, now known as the Company
MDUR Newco Sub	MDUR Newco Sub, Inc., a direct, wholly owned subsidiary of MDUR Newco, which was merged with and into Montana‚Dakota in the Holding Company Reorganization
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million dk
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co. (formerly known as MDU Resources Group, Inc.), a public utility division of the Company prior to the closing of the Holding Company Reorganization and a direct wholly owned subsidiary of MDU Energy Capital as of January 1, 2019
Montana DEQ	Montana Department of Environmental Quality
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NGL	Natural gas liquids
Non-GAAP	Not in accordance with GAAP
Oil	Includes crude oil and condensate
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
Pronghorn	Natural gas processing plant located near Belfield, North Dakota (WBI Energy Midstream's 50€percent ownership interests were sold effective January 1, 2017)
Proxy Statement	Company's 2019 Proxy Statement to be filed no later than April 30, 2019
PRP	Potentially Responsible Party
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission

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
SSIP	System Safety and Integrity Program
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan which was terminated effective December€5, 2016
TCJA	Tax Cuts and Jobs Act
Tesoro	Tesoro Refining & Marketing Company LLC
Thurston County Superior Court	State of Washington Thurston County Superior Court
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada
United States Supreme Court	Supreme Court of the United States
VIE	Variable interest entity
Washington DOE	Washington State Department of Ecology
WBI Energy	WBI Energy, Inc., a direct wholly owned subsidiary of WBI Holdings
WBI Energy Midstream	WBI Energy Midstream, LLC, an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
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
ZRCs	Zonal resource credits - 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 - Business Segment Financial and Operating Data

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 regulated energy delivery and construction materials and services business. Montana-Dakota was incorporated under the laws of the state of Delaware in 1924. The Company was incorporated under the laws of the state of Delaware in 2018. Its principal executive offices are at 1200€West Century Avenue, P.O.€Box€5650, Bismarck, North Dakota 58506-5650, telephone (701)€530-1000.

On November 21, 2017, the Company announced that its board of directors had directed senior management to explore reorganization to a holding company structure. The purpose of the reorganization was to make the public utility divisions into a subsidiary of the holding company, just as the other operating companies are wholly owned subsidiaries. On November 15, 2018, the board of directors approved the Holding Company Reorganization and authorized senior management to take the necessary and appropriate actions to effectuate the Holding Company Reorganization. On January 2, 2019, the Company announced the completion of the Holding Company Reorganization, which resulted in Montana-Dakota and Great Plains becoming a subsidiary of the Company. The merger was conducted pursuant to Section 251(g) of the General Corporation Law of the State of Delaware, which provides for the formation of a holding company without a vote of the stockholders of the constituent corporation. Immediately after consummation of the Holding Company Reorganization, the Company had, on a consolidated basis, the same assets, businesses and operations as Montana-Dakota had immediately prior to the consummation of the Holding Company Reorganization. As a result of the Holding Company Reorganization, the Company became the successor issuer to Montana-Dakota pursuant to Rule 12g-3(a) of the Exchange Act, and as a result, the Company's common stock was deemed registered under Section 12(b) of the Exchange Act.

The Company operates with a two-platform business model. Its regulated energy delivery platform and its construction materials and services platform are each comprised of different operating segments. Some of these segments experience seasonality related to the industries in which they operate. The two-platform approach helps balance this seasonality and the risk associated with each type of industry. Through its regulated energy delivery platform, the Company provides electric and natural gas services to customers, generates, transmits and distributes electricity, and provides natural gas transportation, storage and gathering services. These businesses are regulated by state public service commissions and/or the FERC. The construction materials and services platform provides construction services to a variety of industries, including commercial, industrial and governmental, and provides construction materials through aggregate mining and marketing of related products, such as ready-mixed concrete and asphalt.

The Company is organized into five reportable business segments. These business segments include: electric, natural gas distribution, pipeline and midstream, construction materials and contracting, and construction services. The Company's business segments are determined 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 segments is defined based on the reporting and review process used by the Company's chief executive officer.

The Company, through its wholly owned subsidiary, MDU Energy Capital, owns Montana-Dakota, Cascade and Intermountain. Montana-Dakota, Cascade and Intermountain are the natural gas distribution segment. Montana-Dakota also comprises the electric segment.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings, Knife River, MDU Construction Services, Centennial Resources and Centennial Capital. WBI Holdings is the pipeline and midstream segment, Knife River is the construction materials and contracting segment, MDU Construction Services is the construction services segment, and Centennial Resources and Centennial Capital are both reflected in the Other category.

For more information on the Company's business segments, see Item 8 - Note 15.

As of December 31, 2018, the Company had 11,797 employees with 218 employed at MDU Resources Group, Inc., 1,004 at Montana-Dakota, 338 at Cascade, 242 at Intermountain, 317 at WBI Holdings, 3,967 at Knife River and 5,711 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, 2018.

At Montana-Dakota and WBI Energy Transmission, 349 and 70 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2021, and March 31, 2022, respectively.

At Cascade, 197 employees are represented by the ICWU. The labor contract with the field operations group is effective through March 31, 2021.

At Intermountain, 130 employees are represented by the UA. Labor contracts with such employees are in effect through September 30, 2019.

Knife River operates under 43 labor contracts that represent 673 of its construction materials and contracting employees. Knife River is in negotiations on five of its labor contracts.

MDU Construction Services has 126 labor contracts representing the majority of its employees. MDU Construction Services is not currently in negotiations on any of its labor contracts.

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, and operations of equipment and fleet vehicles. 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.

The Company uses technology in substantially all aspects of its business operations and requires uninterrupted operation of information technology systems and network infrastructure. These systems may be vulnerable to failures or unauthorized access. The Company has policies, procedures and processes in place designed to strengthen and protect these systems, which includes the Company's enterprise information technology and operation technology groups continually evaluating new tools and techniques that can be implemented to reduce the risk of a cyber breach.

The Company created CyROC to oversee the Company's approach to cybersecurity. CyROC is responsible for supplying management at all levels and the Audit Committee with analyses, appraisals, recommendations and pertinent information concerning cyber defense of the Company's electronic information and information technology systems. CyROC provides a quarterly cybersecurity report to the Audit Committee. For a discussion of the Company's risks related to cybersecurity, 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 143,022 residential, commercial, industrial and municipal customers in 184 communities and adjacent rural areas in Montana, North Dakota, South Dakota and Wyoming as of December 31, 2018. For more information on the retail customer classes served, see the table below. The principal properties owned by Montana-Dakota for use in its electric operations include interests in 16 electric generating units at 11 facilities and two small portable diesel generators, as further described under System Supply, System Demand and Competition, approximately 3,200 and 4,900 miles of transmission and distribution lines, respectively, and 75 transmission and 297 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, 2018 , Montana-Dakota's net electric plant investment was $1.5 billion and rate base was $1.2 billion.

The retail customers served and respective revenues by class for the electric business were as follows:

	2018		2017		2016	
	Customers Served	Revenues	Customers Served	Revenues	Customers Served	Revenues
	(Dollars in thousands)					
Residential	118,426	$ 126,173	118,379	$ 121,171	118,483	$ 117,014
Commercial	22,756	141,961	22,764	140,856	22,693	135,390
Industrial	236	36,081	242	34,417	244	31,913
Other	1,604	7,882	1,516	8,275	1,528	7,580
	143,022	$ 312,097	142,901	$ 304,719	142,948	$ 291,897

Other electric revenues for Montana-Dakota were $23.0 million, $38.1 million and $30.4 million for the years ended December 31, 2018 , 2017 and 2016 , respectively.

The percentage of electric retail revenues by jurisdiction was as follows:

	2018	2017	2016
North Dakota	66%	66%	68%
Montana	20%	20%	19%
Wyoming	9%	9%	8%
South Dakota	5%	5%	5%

Retail electric rates, service, accounting and certain security issuances are subject to regulation by the MTPSC, NDPSC, 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 certain securities, accounting and other matters.

Through MISO, Montana-Dakota has access to wholesale energy, ancillary services and capacity markets for its interconnected 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, eastern Montana and northern South Dakota. The interconnected system consists of 15 electric generating units at 10 facilities and two small portable diesel generators, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 750,318 kW and total net ZRCs of 532.3 in 2018. ZRCs are a MW of demand equivalent measure and are allocated to individual generators to meet planning reserve margin requirements within MISO. For 2018, Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 574.5. Montana-Dakota's planning reserve margin requirement within MISO was 537.2 for 2018. The maximum electric peak demand experienced to date attributable to Montana-Dakota's sales to retail customers on the interconnected system was 611,542 kW in August 2015. 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 2023 will approximate two percent annually. Montana-Dakota's interconnected system electric generating capability includes five steam-turbine generating units at four facilities using coal for fuel, four combustion turbine units at three facilities, three wind electric generating facilities, two reciprocating internal combustion engines at one facility, a heat recovery electric generating facility and two small portable diesel generators.

In June 2016, Montana-Dakota and a partner began construction on the BSSE project within the footprint of MISO. Montana-Dakota began bringing the project on-line on February 5, 2019. On October 31, 2018, the Company finalized the purchase and placed into service the Thunder Spirit Wind farm expansion in southwest North Dakota, which includes 16 turbines. With the addition of the expansion, the total Thunder Spirit Wind farm generation capacity is approximately 155 MW. The original 107.5-MW wind farm includes 43 turbines; it was purchased by Montana-Dakota in December 2015. For more information on these projects, see Item 7 - MD&A - Electric and Natural Gas Distribution.

Additional energy is purchased as needed, or in lieu of generation if more economical, from the MISO market, and in 2018, Montana-Dakota purchased approximately 22 percent of its net kWh needs for its interconnected system through the MISO market.

Approximately 21 percent of the electricity delivered to customers from Montana-Dakota's owned generation in 2018 was from renewable resources. Although Montana-Dakota's generation resource capacity has increased to serve the needs of customers, the carbon dioxide emission intensity of the electric generation resource fleet has been reduced by approximately 24 percent since 2003 and is expected to continue to decline.

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 63,686 kW in July 2018. Montana-Dakota has a power supply contract with Black Hills Power, Inc. to purchase up to 49,000 kW of capacity annually through December 31, 2023. 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)	2018 ZRCs (a)	2018 Net Generation (kWh in thousands)
Interconnected System:				
North Dakota:				
Coyote (b)	Steam	103,647	80.8	765,233
Heskett	Steam	86,000	87.4	504,357
Heskett	Combustion Turbine	89,038	61.6	3,981
Glen Ullin	Heat Recovery	7,500	4.8	44,940
Cedar Hills	Wind	19,500	4.4	49,933
Diesel Units	Oil	3,650	3.6	6
Thunder Spirit	Wind	155,500	21.1	407,947
South Dakota:				
Big Stone (b)	Steam	94,111	103.8	521,187
Montana:				
Lewis & Clark	Steam	44,000	50.3	235,882
Lewis & Clark	Reciprocating Internal Combustion Engine	18,700	16.7	8,497
Glendive	Combustion Turbine	75,522	70.6	2,734
Miles City	Combustion Turbine	23,150	21.6	273
Diamond Willow	Wind	30,000	5.6	86,103
		750,318	532.3	2,631,073
Sheridan System:				
Wyoming:				
Wygen III (b)	Steam	28,000	N/A	209,280
		778,318	532.3	2,840,353

(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 Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland Coal Company under contracts that expire in December 2021 and December 2020, respectively. 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 425,000 to 460,000 tons and 250,000 to 350,000 tons per contract year, respectively.

The owners of Coyote Station, including Montana-Dakota, have a contract with Coyote Creek for coal supply to the Coyote Station that expires 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.

The owners of Big Stone Station, including Montana-Dakota, have a coal supply agreement with Peabody COALSALES, LLC to meet all of the Big Stone Station's fuel requirements for 2019 and 2020, with the exception of 250,000 tons in 2019, which was previously committed to be purchased from Contura Coal Sales, LLC, all at contracted pricing.

Montana-Dakota has a coal supply agreement with Wyodak Resources Development Corp., 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,	2018	2017	2016
Average cost of coal per MMBtu	$ 2.00	$ 2.07	$ 1.89
Average cost of coal per ton	$ 29.08	$ 30.04	$ 27.45

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 2028. Future capacity that is needed to replace contracts, generation retirements 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.

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's results of operations reflect monthly increases or decreases in electric fuel and purchased power costs (including demand charges) and Montana-Dakota 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's results of operations to reflect 90 percent of the increases or decreases in electric 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's jurisdictional electric rate schedules allows Montana-Dakota's results of operations to reflect monthly increases or decreases in electric fuel and purchased power costs. In Wyoming, an annual Electric Power Supply Cost Adjustment mechanism allows Montana-Dakota's results of operations to reflect increases or decreases in purchased power costs (including demand charges) 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 which are filed annually. Montana-Dakota's results of operations reflect 95 percent of the increases or decreases from the base purchased power costs and in addition also reflects 85 percent of the increases or decreases from the base coal price, which is also recovered through the Electric Power Supply Cost Adjustment. For more information on regulatory assets and liabilities, see Item 8 - Note

For the Thunder Spirit Wind project, Montana-Dakota implemented a renewable resource cost adjustment rider, and all of Montana-Dakota's wind resources pertaining to North Dakota electric operations were placed in this rider upon a final order of the most recent North Dakota electric general rate case. Montana-Dakota also has in place in North Dakota a transmission tracker to recover transmission costs associated with MISO and the Southwest Power Pool, regional transmission organizations serving parts of Montana-Dakota's system, along with certain of the transmission investments not recovered through retail rates. The tracking mechanism has an annual true-up.

In South Dakota, Montana-Dakota recovers the South Dakota investment in the Thunder Spirit Wind project through an Infrastructure Rider tracking mechanism that is subject to an annual true-up. Montana-Dakota also has in place in South Dakota a transmission tracker to recover transmission costs associated with MISO and the Southwest Power Pool, regional transmission organizations serving parts of Montana-Dakota's system, along with certain of the transmission investments not recovered through retail rates. This tracking mechanism also has an annual true-up.

In Montana, Montana-Dakota recovers in rates through a tracking mechanism the increases associated with its allocated share of Montana state and local taxes assessed to electric operations on an after tax basis.

For more information on regulatory matters, see Item 8 - Note 18.

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 timely to the North Dakota Department of Health in September 2017, with the permit expected to be issued in 2019. Wygen III is allowed to operate under the facility's construction permit until the Title V Operating Permit is issued by the Wyoming Department of Environmental Quality. The Title V Operating Permit application for Wygen III was submitted timely in January 2011, with the permit expected to be issued in 2019.

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 very small-quantity generators of hazardous waste and subject only to minimum regulation under the RCRA. Montana-Dakota routinely handles PCBs from its electric operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required.

Montana-Dakota incurred $9.2 million of environmental capital expenditures in 2018, mainly for coal ash management projects at Lewis & Clark Station, Big Stone Station and Coyote Station. Environmental capital expenditures are estimated to be $6.8 million, $2.7 million and $1.8 million in 2019, 2020 and 2021, respectively, for various environmental projects, including coal ash management at power plants. Montana-Dakota's capital and operational expenditures could also be affected by future air emission regulations, including a future GHG regulation that may replace the Clean Power Plan rule published by the EPA in October 2015. The Clean Power Plan requires existing fossil fuel-fired electric generating facilities to reduce carbon dioxide emissions. For more information, see Item 1A - Risk Factors.

Natural Gas Distribution

General The Company's natural gas distribution operations consist of Montana-Dakota, Cascade and Intermountain, which sell natural gas at retail, serving 957,727 residential, commercial and industrial customers in 339 communities and adjacent rural areas across eight states as of December 31, 2018, and provide natural gas transportation services to certain customers on the Company's systems. For more information on the retail customer classes served, see the table below. These services are provided through distribution systems aggregating approximately 19,400 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, 2018, the natural gas distribution operations' net natural gas distribution plant investment was $1.7 billion and rate base was $1.1 billion.

The retail customers served and respective revenues by class for the natural gas distribution operations were as follows:

	2018		2017		2016	
	Customers Served	Revenues	Customers Served	Revenues	Customers Served	Revenues
	(Dollars in thousands)					
Residential	850,595	$ 464,697	833,255	$ 477,699	818,163	$ 429,828
Commercial	106,297	279,566	104,795	283,899	103,438	253,333
Industrial	835	24,555	817	24,030	807	23,337
	957,727	$ 768,818	938,867	$ 785,628	922,408	$ 706,498

Transportation and other revenues for the natural gas distribution operations were $54.4 million, $62.8 million and $59.6 million for the years ended December 31, 2018, 2017 and 2016, respectively.

The percentage of the natural gas distribution operations' retail sales revenues by jurisdiction was as follows:

	2018	2017	2016
Idaho	30%	33%	34%
Washington	26%	26%	26%
North Dakota	15%	13%	13%
Montana	9%	9%	8%
Oregon	8%	8%	8%
South Dakota	7%	6%	6%
Minnesota	3%	3%	3%
Wyoming	2%	2%	2%

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; western Minnesota; eastern Montana; North Dakota; central and eastern Oregon; western and north-central South Dakota; western, southeastern and south-central Washington; and northern Wyoming. 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, Northern Border Pipeline Company, Northwest Pipeline LLC, South Dakota Intrastate Pipeline, TransCanada Corporation, Northern Natural Gas, Gas Transmission Northwest LLC, Northwestern Energy, Viking Gas Transmission Company, Westcoast Energy Inc., Ruby Pipeline LLC, Foothills Pipe Lines Ltd. and NOVA Gas Transmission Ltd. 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, Dominion Energy Questar Pipeline, LLC, Northwest Pipeline LLC 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 through rate adjustments which are filed annually.

Montana-Dakota's North Dakota and South Dakota natural gas tariffs contain weather normalization mechanisms applicable to certain firm customers that adjust the distribution delivery charge revenues to reflect weather fluctuations during the November 1 through May 1 billing periods.

In Montana, Montana-Dakota recovers in rates through a tracking mechanism the increases associated with Montana state and local taxes assessed to natural gas operations on an after tax basis.

In Minnesota and Washington, Great Plains and Cascade recover in rates through a cost recovery tracking mechanism, qualifying capital investments related to the safety and integrity of its pipeline system.

On December 28, 2015, the OPUC approved an extension of Cascade's decoupling mechanism until January 1, 2020, with an agreement that Cascade would initiate a review of the mechanism by September 30, 2019. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

On July 7, 2016, the WUTC approved a full decoupling mechanism where Cascade is allowed recovery of an average revenue per customer regardless of actual consumption. The mechanism also includes an earnings sharing component if Cascade earns beyond its authorized return. The decoupling mechanism will be reviewed by Cascade following the end of 2019.

On December 22, 2016, the MNPUC approved a request by Great Plains to implement a full revenue decoupling mechanism pilot project for three years. The decoupling mechanism will reflect the period January 1 through December 31. Great Plains intends to seek continuation of the decoupling mechanism effective upon expiration of the pilot project.

For more 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 Company believes its natural gas distribution operations are in substantial compliance with those regulations.

The Company's natural gas distribution operations are very small-quantity generators of hazardous waste, and subject only to minimum regulation under the RCRA. Washington state rule defines Cascade as a small-quantity generator, but regulation under the rule is similar to 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 2018. Except as to what may be ultimately determined with regard to the issues described in the following paragraph, the natural gas distribution operations do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2021.

Montana-Dakota has ties to six historic manufactured gas plants as a successor corporation or through direct ownership of the plant. Montana-Dakota is investigating one of these former manufactured gas plant sites and providing input on another site investigation conducted by a third party. To the extent not covered by insurance, Montana-Dakota may seek recovery in its natural gas rates charged to customers for certain investigation and remediation costs incurred for these sites. Cascade has ties to nine historic manufactured gas plants as a successor corporation or through direct ownership of the plant. Cascade is involved in the investigation and remediation of three of these 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 not covered by insurance, Cascade will seek recovery of investigation and remediation costs through its natural gas rates charged to customers.

Pipeline and Midstream

General WBI Energy owns and operates both regulated and nonregulated businesses. The regulated business of this segment, WBI Energy Transmission, owns and operates approximately 4,000 miles of natural gas transmission, gathering and storage lines in Minnesota, Montana, North Dakota, South Dakota and Wyoming. WBI Energy Transmission's underground storage fields in Montana and Wyoming provide storage services to local distribution companies, industrial customers, natural gas marketers and others, and serve to enhance system reliability. 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 14 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, 2018, its net plant investment was $458.1 million.

The nonregulated business of this segment owns and operates gathering facilities in Montana and Wyoming. In total, facilities include approximately 800 miles of operated field gathering lines, some of which interconnect with WBI Energy's regulated pipeline system. The nonregulated business provides natural gas gathering services and a variety of other energy-related services, including cathodic protection and energy efficiency product sales and installation services to large end-users.

A majority of its pipeline and midstream business is transacted in the northern Great Plains and Rocky Mountain regions of the United States.

System Supply, System Demand and Competition Natural gas supplies emanate from traditional and nontraditional production activities in the region from both on-system and off-system supply sources. New incremental supply from nontraditional sources have developed, such as the Bakken area in Montana and North Dakota, which has helped offset declines in traditional regional supply sources and supports WBI Energy Transmission's transportation and storage services. In addition, off-system supply sources are available through the Company's interconnections with other pipeline systems. WBI Energy Transmission continues 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 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, commercial and industrial 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 2018 represented 32 percent of WBI Energy Transmission's subscribed firm transportation contract demand. The majority of the firm transportation agreements with Montana-Dakota expire in June 2022. In addition, Montana-Dakota has contracts with WBI Energy Transmission to provide firm storage services to facilitate meeting Montana-Dakota's winter peak requirements expiring in July 2035.

The nonregulated business competes for existing customers in the fields in which it operates. Its focus on customer service and the variety of services it offers serve to enhance its competitive position.

Environmental Matters The pipeline and midstream 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 RCRA 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 as required by the National Environmental Policy Act are included in the FERC's environmental review process for both the construction and abandonment of WBI Energy Transmission's natural gas transmission pipelines, compressor stations and storage facilities.

The pipeline and midstream operations did not incur any material environmental expenditures in 2018 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2021.

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, South Dakota, 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. These products are used in most types of construction, performed by Knife River and other companies, including roads, freeways and bridges, as well as homes, schools, shopping centers, office buildings and industrial parks. Knife River focuses on vertical integration of its contracting services with its construction materials to support the aggregate based product lines including aggregate placement, asphalt and concrete paving, and site development and grading. 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.

During 2018, Knife River acquired construction materials and contracting businesses with operations in Oregon, Minnesota and South Dakota. For more information on acquisitions, see Item 8 - Note 3.

Knife River's backlog was approximately $706 million, $486 million and $538 million at December 31, 2018, 2017 and 2016, respectively. The increase in backlog at December 31, 2018, compared to backlog at December 31, 2017, was primarily attributable to higher backlog of federal and state agency work, as well as higher backlog of private construction projects. Backlog increases with awards of new contracts and decreases as work is performed on existing contracts. Knife River expects to complete a significant amount of the backlog at December 31, 2018, during the next 12 months.

Knife River's backlog is comprised of the anticipated revenues from the uncompleted portion of services to be performed under job-specific contracts. A project is included in backlog when a contract is awarded and agreement on contract terms has been reached. However, backlog does not contain contracts for time and material projects that a fixed amount cannot be determined. Backlog is comprised of: (a) original contract amounts, (b) change orders for which customers have approved and (c) claim amounts that have been made against customers for which are determined to have a legal basis under existing contractual arrangements and as to which recovery is considered to be probable. Such claim amounts were immaterial for all periods presented. Backlog may be subject to delay, default or cancellation at the election of the customers. Historically, cancellations have not had a materially adverse effect on backlog. Due to the nature of its contractual arrangements, in many instances Knife River's customers are not committed to the specific volumes of services to be purchased under a contract, but rather Knife River 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, or backlog estimates in general, at any point in time are predictive of future revenues.

Competition€Knife River's construction materials products and contracting services are marketed under highly competitive conditions. Price is the principal competitive force to which these products and services are subject, with service, quality, delivery time and proximity to the customer also being significant factors. Knife River focuses on markets located near aggregate sites to reduce transportation costs which allows Knife River to remain competitive with the pricing of aggregate products. 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 and contracting services is significantly influenced by the cyclical nature of the construction industry in general. In addition, construction materials and contracting services 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 on roads and infrastructure projects, general economic conditions within the market area that influence both the commercial and residential sectors, and prevailing interest rates.

Knife River's customers are a diverse group which includes federal, state and municipal government agencies, commercial and residential developers, and private parties. The mix of sales by customer will vary each year depending on the work available. 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 InformationAggregate 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.

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 938€million tons of the 1.0€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, including estimated sales from acquired reserves prior to acquisition, from 2016 through 2018 . 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, 2018, and sales for the years ended December€31, 2018, 2017 and 2016:

Production Area	Number of Sites (Crushed Stone) owned	Number of Sites (Crushed Stone) leased	Number of Sites (Sand & Gravel) owned	Number of Sites (Sand & Gravel) leased	Tons Sold (000's) 2018	Tons Sold (000's) 2017	Tons Sold (000's) 2016	Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
Anchorage, AK	„	„	1	„	725	1,425	1,343	13,823	N/A	12
Hawaii	„	5	„	„	1,734	1,614	1,901	49,159	2023-2064	28
Northern CA	„	„	9	1	1,798	1,785	1,604	42,720	2028	25
Southern CA	„	2	„	„	356	55	224	91,211	2035	Over 100
Portland, OR	2	4	5	3	5,402	4,694	4,044	212,822	2028-2057	45
Eugene, OR	3	4	5	„	743	633	662	153,301	2021-2049	Over 100
Central OR/WA/ID	„	1	6	2	2,362	2,160	1,685	85,396	2020-2087	41
Southwest OR	5	5	10	6	2,395	2,367	2,689	108,998	2021-2053	44
Central MT	„	„	3	1	1,081	1,065	1,135	15,238	2023	14
Northwest MT	„	„	9	1	1,965	1,745	1,514	63,182	2020	36
Wyoming	„	„	1	2	626	613	742	9,466	2019-2020	14
Central MN	1	1	43	7	2,890	2,773	2,831	65,225	2019-2028	18 *
Northern MN	2	„	14	2	369	270	537	21,062	2020-2021	54
ND/SD	1	„	3	24	1,506	1,100	1,643	74,214	2019-2031	17 *
Texas	1	2	1	„	1,094	1,192	1,243	8,614	2022-2029	7
Sales from other sources					4,749	4,722	3,783			
					29,795	28,213	27,580	1,014,431		

* Includes estimate of three-year average sales for acquired reserves.

The 1.0€billion tons of estimated aggregate reserves at December€31, 2018, are comprised of 518€million tons that are owned and 496€million tons that are leased. Approximately 48€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 23€years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2016 through 2018 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 44€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 were as follows:

	2018	2017	2016
	(000's of tons)		
Aggregate reserves:			
Beginning of year	965,036	989,084	1,022,513
Acquisitions (a)	81,004	2,726	24,993
Sales volumes (b)	(25,046)	(23,491)	(23,797)
Other (c)	(6,563)	(3,283)	(34,625)
End of year	1,014,431	965,036	989,084

(a) Includes reserves from acquisitions of businesses.
(b) Excludes sales from other sources.
(c) Includes property sales, revisions of previous estimates and expiring leases.

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 the Clean Air Act and the 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 the 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 has 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 are also 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 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 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 Surface Mining Control and Reclamation Act, 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.

Knife River did not incur any material environmental expenditures in 2018 and, except as to what may be ultimately determined with regard to the issues described in the following paragraph, Knife River does not expect to incur any material expenditures related to environmental compliance with current laws and regulations through 2021.

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 more information, see Item€8 - Note€19.

Mine Safety€The Dodd-Frank Act requires disclosure of certain mine safety information. For more information, see Item€4 - Mine Safety Disclosures.

Construction Services

General MDU Construction Services provides inside and outside specialty contracting services. Its outside services include design, construction and maintenance of overhead and underground electrical distribution and transmission lines, substations, external lighting, traffic signalization, and gas pipelines, as well as utility excavation and the manufacture and distribution of transmission line construction equipment. Its inside services include design, construction and maintenance of electrical and communication wiring and infrastructure, fire suppression systems, and mechanical piping and services. This segment also constructs and maintains renewable energy projects. These specialty contracting 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, 2018, MDU Construction Services owned or leased facilities in 18€states. This space is used for offices, equipment yards, manufacturing, warehousing, storage and vehicle shops.

MDU Construction Servicesƒ backlog at December 31 was as follows:

		2018		2017		2016
			(In millions)			
Inside specialty contracting	$	814	$	625	$	435
Outside specialty contracting		125		83		40
	$	939	$	708	$	475

The increase in backlog at December€31, 2018, compared to backlog at December€31, 2017, was primarily attributable to an increase in projects from all revenue streams based on customer demand. Backlog increases with awards of new contracts and decreases as work is performed on existing contracts. MDU Construction Services expects to complete a significant amount of the backlog at December€31, 2018 , during the next 12 months.

MDU Construction Servicesƒ backlog is comprised of the anticipated revenues from the uncompleted portion of services to be performed under job-specific contracts. A project is included in backlog when a contract is awarded and agreement on contract terms has been reached. However, backlog does not contain contracts for time and material projects that a fixed amount cannot be determined. Backlog is comprised of: (a) original contract amounts, (b) change orders for which customers have approved, (c) pending change orders expected to receive confirmation in the ordinary course of business and (d) claim amounts that have been made against customers for which are determined to have a legal basis under existing contractual arrangements and as to which recovery is considered to be probable. Such claim amounts were immaterial for all periods presented. Backlog may be subject to delay, default or cancellation at the election of the customers. Historically, cancellations have not had a material adverse effect on backlog. 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, or backlog estimates in general, 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 2018 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2021 .

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. If any of the risks described below actually occur, the Company's business, prospects, financial condition or financial results could be materially harmed.

Economic Risks

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 or impose conditions on an acquisition of or by the Company.

The Company's electric and natural gas transmission and distribution businesses are subject to comprehensive regulation by federal, state and local regulatory agencies with respect to, among other things, allowed rates of return and recovery of investment and cost, financing, rate structures, customer service, health care coverage and cost, income taxes, property and other taxes, franchises; recovery of purchased power and purchased natural gas costs; construction and siting of generation and transmission facilities. 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 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.

There can be no assurance that applicable regulatory commissions will determine that the Company's electric and natural gas transmission and distribution businesses' costs have been prudent, which could result in disallowance of costs. Also, the regulatory process for approving rates for these businesses may not allow us full recovery of the costs of providing services or a return on the Company's invested capital. Changes in regulatory requirements or operating conditions may require early retirement of certain assets. While regulation typically provides relief for these types of retirements, there is no assurance that regulators will allow full recovery of all remaining costs, which could leave stranded asset costs. Rising fuel costs could increase the risk that the utility businesses will not be able to fully recover those fuel costs from customers.

Approval from a number of federal and state regulatory agencies would need to be obtained by any potential acquirer of the Company, as well as for acquisitions by the Company. The approval process could be lengthy and the outcome uncertain, which may deter potential acquirers from approaching the Company or impact the Company's ability to pursue acquisitions.

Economic volatility affects the Company's operations, as well as the demand for its products and services.

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 general economy. State and federal budget issues affect the funding available for infrastructure spending.

Economic conditions and population growth affect the electric and natural gas distribution businesses' growth in service territory, customer base and usage demand. Economic volatility in the markets served, along with economic conditions such as increased unemployment which could impact the ability of our customers to make payments, could adversely affect the Company's results of operations, cash flows and asset values. Further, any material decreases in customers' energy demand, for economic or other reasons, could have a material adverse impact on the Company's earnings and results of operations.

The Company's operations involve risks that may result from catastrophic events.
The Company's operations, particularly those related to natural gas and electric transmission and distribution, include a variety of inherent hazards and operating risks, such as product leaks, explosions, mechanical failures, vandalism, fires, acts of terrorism and acts of war which could result in loss of human life; personal injury; property damage; environmental pollution; impairment of operations; and substantial financial losses. The Company maintains insurance against some, but not all, of these risks and losses. A significant incident could also increase regulatory scrutiny and result in penalties and higher amounts of capital expenditures and operational costs. Losses not fully covered by insurance could have a material effect on the Companyƒs financial position, results of operations and cash flows.

A disruption of the regional electric transmission grid or interstate natural gas infrastructure could negatively impact our business and reputation. Because the Company's electric and natural gas utility and pipeline systems are part of larger interconnecting systems, a disruption could result in a significant decrease in revenues and system repair costs which could have a material impact on the Company's financial position, results of operations and cash flows.

The Company is subject to capital market and interest rate risks.
The Company's operations, particularly its electric and natural gas transmission and distribution businesses, require significant capital investment. Consequently, the Company relies on financing sources and capital markets as sources of liquidity for capital requirements not satisfied by its cash flows from operations. If the Company is not able to access capital at competitive rates, the ability to implement its business plans, make capital expenditures or pursue acquisitions that the Company would otherwise rely on for future growth may be adversely affected. Market disruptions may increase the cost of borrowing or adversely affect the Company's ability to access one or more financial markets. Such disruptions could include:

- A significant economic downturn.
- The financial distress 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.
- Cyberattacks.

The issuance of a substantial amount of the Company's common stock, whether issued in connection with an acquisition or otherwise, or the perception that such an issuance could occur, could have a dilutive effect on shareholders and/or may adversely affect the market price of the Company's common stock. Higher interest rates on borrowings could also have an adverse effect on the Company's operating results.

Financial market changes could impact the Company•s pension and postretirement benefit plans and obligations.
The Company has pension and postretirement defined benefit plans for some of its employees and former employees. Assumptions regarding future costs, returns on investments, interest rates, and other actuarial assumptions have a significant impact on the funding requirements relating to these plans. Changes in economic indicators, such as consumer spending, inflation data, interest rate changes, political developments and threats of terrorism, among other things, can create volatility in the financial markets. Deteriorating financial market conditions could change these estimates and assumptions and negatively affect the 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 for those plans.

Significant changes in energy prices could negatively affect the Company's businesses.
Fluctuations in oil, NGL and natural gas production and prices; fluctuations in commodity price basis differentials; supplies of domestic and foreign oil, NGL and natural gas; political and economic conditions in oil-producing countries; actions of the Organization of Petroleum Exporting Countries; and other external factors impact the development of natural gas supplies and the expansion and operation of natural gas pipeline systems. Prolonged depressed prices for oil, NGL and natural gas could negatively affect the growth, results of operations, cash flows and asset values of the Company's pipeline and midstream business.

If oil and natural gas prices increase significantly, customer demand for utility, pipeline and midstream, and construction materials could decline, which could have a material impact on the Company's results of operations and cash flows. While the Company has fuel clause recovery mechanisms for its utility operations in most of the states in which it operates, higher utility fuel costs could significantly impact results of operations if such costs are not recovered. Delays in the collection of utility fuel cost recoveries, as compared to expenditures for fuel purchases, could have a negative impact on the Company's cash flows. High oil prices also affect the cost and demand for asphalt products and related contracting services. Low commodity prices could have a positive impact on sales but could negatively impact oil and natural gas production activities and subsequently the Company's pipeline and construction revenues in energy producing states in which the Company operates.

Reductions in the Company's credit ratings could increase financing costs.
There is no assurance that the Company's current credit ratings, or those of its subsidiaries, will remain in effect or that a rating will not be lowered or withdrawn by a rating agency. Events affecting the Company's financial results may impact its cash flows and credit metrics, potentially resulting in a change in the Company's credit ratings. The Company's credit ratings may also change as a result of the differing methodologies or changes in the methodologies used by the rating agencies. A downgrade in credit ratings could lead to higher borrowing costs.

Increasing costs associated with health care plans may adversely affect the Company's results of operations.
The Company's self-insured costs of health care benefits for eligible employees continues to increase. Increasing quantities of large individual health care claims and an overall increase in total health care claims could have an adverse impact on operating results, financial position and liquidity. Legislation related to health care could also change the Company's benefit program and costs.

The Company is exposed to risk of loss resulting from the nonpayment and/or nonperformance by the Company's customers and counterparties
If the Company's customers or counterparties experience financial difficulties, the Company could experience difficulty in collecting receivables. Nonpayment and/or nonperformance by the Company's customers and counterparties, particularly customers and counterparties of the Companyƒs construction materials and contracting and construction services businesses for large construction projects, could have a negative impact on the Company's results of operations and cash flows. The Company could also have indirect credit risk from participating in energy markets such as MISO in which credit losses are socialized to all participants.

Changes in tax law may negatively affect the Company's business.
The TCJA significantly reformed the Internal Revenue Code of 1986, as amended. The TCJA, among other things, includes reductions to United States federal tax rates, repeals the domestic production deduction, disallows regulated utility property for immediate expensing, and modifies or repeals many other business deductions and credits. Any future guidance, regulation and interpretations to the Internal Revenue Code could have an adverse impact on the Company.

Other changes to federal and state tax laws have the ability to benefit or adversely affect the Company's earnings and customer costs. Significant changes to corporate tax rates could result in the impairment of deferred tax assets that are established based on existing law at the time of deferral. Changes to the value of various tax credits could change the economics of resources and the resource selection for the electric generation business. Regulation incorporates changes in tax law into the rate-setting process for the regulated energy delivery businesses and therefore could create timing delays before the impact of changes are realized.

The Company's operations could be negatively impacted by import tariffs and/or other government mandates.
The Company operates in or provides services to capital intensive industries in which federal trade policies could significantly impact the availability and cost of materials. Imposed and proposed tariffs could significantly increase the prices and delivery lead times on raw materials and finished products that are critical to the Company and its customers, such as aluminum and steel. Prolonged lead times on the delivery of raw materials and further tariff increases on raw materials and finished products could have a material adverse effect on the Company's business, financial condition and results of operations.

Operational Risks

Significant portions of the Company•s natural gas pipelines and power generation and transmission facilities are aging. The aging infrastructure may require significant additional maintenance or replacement that could adversely affect the Company•s results of operations.
The Companyƒs energy delivery infrastructure is aging, which increases certain risks, including breakdown or failure of equipment, pipeline leaks and fires developing from power lines. Aging infrastructure is more prone to failure which increases maintenance costs, unplanned outages and the need to replace facilities. Even if properly maintained, reliability may ultimately deteriorate and negatively affect the Companyƒs ability to serve its customers which could result in increased costs associated with regulatory oversight. The costs associated with maintaining the aging infrastructure and capital expenditures for new or replacement infrastructure could cause rate volatility and/or regulatory lag in some jurisdictions. If, at the end of its life, the investment costs of a facility have not been fully recovered the Company may be adversely affected if commissions do not allow such costs to be recovered in rates. Such impacts of an aging infrastructure could have a material adverse effect on the Companyƒs results of operations and cash flows.

Additionally, hazards from aging infrastructure could result in serious injury, loss of human life, significant damage to property, environmental impacts, and impairment of operations, which in turn could lead to substantial losses. The location of distribution mains and storage facilities near populated areas, including residential areas, business centers, industrial sites, and other public gathering places, could increase the level of damages resulting from these risks. A major domestic incident involving natural gas systems could lead to additional capital expenditures, increased regulation, and fines and penalties on natural gas utilities. The occurrence of any of these events could adversely affect the Companyƒs results of operations, financial position, and cash flows.

The Company's utility and pipeline operations are subject to planning risks.
Most electric and natural gas utility investments, including natural gas pipeline investments, are made with the intent of being used for decades. In particular, electric transmission and generation resources are planned well in advance of when they are placed into service based upon resource plans using assumptions over the planning horizon; including sales growth, commodity prices, equipment and construction costs, regulatory treatment, available technology and public policy. Public policy changes and technology advancements related to areas such as energy efficient appliances and buildings, renewable and distributive electric generation and storage, carbon dioxide emissions, electric vehicle penetration, and natural gas availability and cost may significantly impact the planning assumptions. Changes in critical planning assumptions may result in excess generation, transmission and distribution resources creating increased per customer costs and downward pressure on load growth. These changes could also result in a stranded investment if the Company is unable to fully recover the costs of its investments.

The regulatory approval, permitting, construction, startup and/or operation of pipelines and power generation and transmission facilities may involve unanticipated events, delays and unrecoverable costs.
The construction, startup and operation of pipelines and power generation and transmission facilities involve many risks, which may include delays; breakdown or failure of equipment; inability to obtain required governmental permits and approvals; inability to obtain or renew easements; public opposition; inability to complete financing; inability to negotiate acceptable equipment acquisition, construction, fuel supply, off-take, transmission, transportation or other material agreements; changes in markets and market prices for power; cost increases and overruns; the risk of performance below expected levels of output or efficiency; and the inability to obtain full cost recovery in regulated rates. Such unanticipated events could negatively impact the Company's business, its results of operations and cash flows.

Additionally, operating or other costs required to comply with current pipeline safety regulations and potential new regulations under various agencies could be significant. The regulations require verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of certain lines. Increased emphasis on pipeline safety and increased regulatory scrutiny may result in penalties and higher costs of operations. If these costs are not fully recoverable from customers, they could have a material adverse effect on the Companyƒs results of operations and cash flows.

The backlogs at the Company's construction materials and contracting and construction services businesses may not accurately represent future revenue.
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. Accordingly, there is no assurance that backlog will be realized. The timing of contract awards, duration of large new contracts and the mix of services can significantly affect backlog. Backlog at any given point in time may not accurately represent the revenue or net income that is realized in any period, and the backlog as of the end of the year may not be indicative of the revenue and net income expected to be earned in the following year and should not be relied upon as a stand-alone indicator of future revenues or net income.

Environmental and Regulatory Risks

The Company's operations could be adversely impacted by climate change.
Severe weather events, such as tornadoes, rain, ice and snow storms and high and low temperature extremes, do occur in regions in which the Company operates and maintains infrastructure. However, climate change could possibly change the frequency and severity of these weather events. Climate change may create physical and financial risks to the Company. Such risks could have an adverse effect on the Company's financial condition, results of operations and cash flows.

Utility customersƒ energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent the largest energy use. To the extent weather conditions are affected by climate change, customersƒ energy use could increase or decrease. Increased energy use by its utility customers due to weather may require the Company to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather may result in decreased revenues. Extreme weather conditions, such as uncommonly long periods of high or low ambient temperature, in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of the Company's service territory could also have an impact on revenues. The Company buys and sells electricity that might be generated outside its service territory, depending upon system needs and market opportunities. Extreme temperatures may create high energy demand and raise electricity prices, which could increase the cost of energy provided to customers.

Severe weather events may damage or disrupt the Company's electric and natural gas transmission and distribution facilities, which could increase costs to repair facilities and restore service to customers. The cost of providing service could increase to the extent the frequency of severe weather events increases because of climate change or otherwise. The Company may not recover all costs related to mitigating these physical risks.

Severe weather may result in disruptions to the pipeline and midstream business's natural gas supply and transportation systems, potentially increasing the cost of gas and the ability to procure gas to meet customer demand. These changes could result in increased maintenance and capital costs, disruption of service, regulatory actions and lower customer satisfaction.

Increases in severe weather conditions or extreme temperature may cause infrastructure construction projects to be delayed or canceled and limit resources available for such projects resulting in decreased revenue or increased project costs at the construction materials and contracting and construction services businesses. In addition, drought conditions could restrict the availability of water supplies, inhibiting the ability of the construction businesses to conduct operations.

Climate change may impact a regionƒs economic health, which could impact revenues at all of the Company's businesses. The Company's financial performance is tied to the health of the regional economies served. The Company provides natural gas and electric utility service, as well as construction materials and services, for some states and communities that are economically affected by the agriculture industry. Increases in severe weather events or significant changes in temperature and precipitation patterns could adversely affect the agriculture industry and, correspondingly, the economies of the states and communities affected by that industry.

The Company may also be subject to litigation related to climate change. Costs of such litigation could be significant, and an adverse outcome could require substantial capital expenditures, changes in operations and possible payment of penalties or damages which could affect the Company's results of operations and cash flows if the costs are not recoverable in rates.

The price of energy also has an impact on the economic health of communities. The cost of additional regulatory requirements to combat climate change, such as regulation of carbon dioxide emissions under the Clean Air Act, or other environmental regulation could impact the availability of goods and prices charged by suppliers, which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect the Company's ability to access capital markets or cause less than ideal terms and conditions.

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 operations, including air and water quality, waste management and other environmental considerations. These laws and regulations can increase 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 relating to electric generation and natural gas gathering, transmission and storage operations. Environmental laws and regulations can also require the Company to install pollution control equipment at its facilities, clean up spills and other contamination and correct environmental hazards, including payment of all or part of the cost to remediate sites where the Company's past activities, or the activities of other parties, caused environmental contamination. These laws and regulations generally require the Company to obtain and comply with a variety of environmental licenses, permits, inspections and other approvals and may cause the Company to shut down existing facilities due to difficulties in assuring compliance or where the cost of compliance makes operation of the facilities no longer economical. Although the Company strives to comply with all applicable environmental laws and regulations, public and private entities and private individuals may interpret the Company's legal or regulatory requirements differently and seek injunctive relief or other remedies against the Company. The Company cannot predict the outcome, financial or operational, of any such litigation or administrative proceedings.

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; retire and replace certain facilities; install pollution controls; remediate environmental impacts; remove or reduce environmental hazards; or forego or limit the development of resources. Revised or new laws and regulations that increase compliance costs or restrict operations, particularly if costs are not fully recoverable from customers, could have a material adverse effect on the Company's results of operations and cash flows.

On April€17, 2015, the EPA published a rule, under the RCRA, for coal combustion residuals that regulates coal ash as a solid waste and not a hazardous waste. Some of the Company's coal fired electric generating facilities are subject to this rule. Company facilities where there are ash impoundments and landfills are conducting ground water evaluations and may need to implement projects to meet rule requirements.

On August€15, 2014, the EPA published a rule under Section€316(b) of the Clean Water Act, establishing requirements for water intake structures at existing steam electric generating facilities. The purpose of the rule is to reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures. The majority of the Company's electric generating facilities are either not subject to the rule or have completed studies that project compliance expenditures are not material. The Lewis & Clark Station will complete a study that will be submitted to the Montana DEQ by July€31, 2019, to be used in determining any required controls. It is unknown at this time what controls may be required at this facility or if compliance costs will be material. The installation schedule for any required controls would be established with the permitting agency after the study is completed.

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. The Companyƒs primary GHG emission is carbon dioxide from fossil fuels combustion at Montana-Dakota's electric generating facilities, particularly its coal-fired facilities. Approximately 46 percent of Montana-Dakota's owned generating capacity and approximately 79€percent of the electricity it generated in 2018 was from coal-fired facilities.

On October€23, 2015, the EPA published the Clean Power Plan rule that requires existing fossil fuel-fired electric generating facilities to reduce carbon dioxide emissions. On February€9, 2016, however, the United States Supreme Court granted an application for a stay of the Clean Power Plan pending disposition of the applicants' petition for review in the D.C. Circuit Court and disposition of the applicants' petition for a writ of certiorari if such a writ is sought. The EPA filed a motion with the D.C. Circuit Court on March 28, 2017, requesting the Clean Power Plan's case be held in abeyance, which was granted. The D.C. Circuit Court has continued to issue orders holding the case in abeyance and requiring the EPA to file ongoing status reports. In parallel, the EPA published a proposal on October 16, 2017, to repeal the Clean Power Plan in its entirety and published the proposed Affordable Clean Energy rulemaking to revise the Clean Power Plan. The proposed revised rule would require states to conduct a review of heat rate improvement projects that could be implemented at each individual coal-fired electric generating facility and determine, using a multi-factor analysis, which projects a facility would need to implement. The state would establish a standard of performance for carbon dioxide emissions for each facility based on the heat rate improvement projects required to be implemented. Compliance costs will become clearer as the EPA completes new rulemaking.

On January€14, 2015, the federal government announced a goal to reduce methane emissions from the oil and natural gas industry by 40€to 45€percent below 2012 levels by 2025. On June 3, 2016, the EPA published a rule updating new-source performance standards for the oil and natural gas industry. The rule builds on 2012 requirements to reduce volatile organic compound emissions from oil and natural gas sources by establishing requirements to reduce methane emissions from previously regulated sources, as well as adding volatile organic compound and methane requirements for sources previously not covered by the rule. WBI Energy is currently complying with the rules impacting new and modified sources. In addition, on March€10, 2016, the EPA announced plans to reduce emissions from the oil and natural gas industry by moving to regulate emissions from existing sources. On November€10, 2016, the EPA issued an Information Collection Request to oil and gas facility operators, including WBI Energy, to begin the process of existing source rule development. On March€7, 2017, the EPA published notice of withdrawal of the Information Collection Request.

On September 15, 2016, the Washington DOE issued a Clean Air Rule that requires carbon dioxide emission reductions from various industries in the state, including emissions from the combustion of natural gas supplied to end-use customers by natural gas distribution companies, such as Cascade. In 2017, the rule requires Cascade to hold carbon dioxide emissions to a baseline, equal to the average emissions in 2012 to 2016. Beginning in 2018, annual carbon dioxide emissions are reduced by an additional 1.7 percent of the baseline from the previous year's emissions. Compliance for natural gas suppliers is to be achieved through purchasing emissions credits from projects located within the state of Washington and, to a limited and declining extent, out-of-state allowances. Purchasing emissions credits and allowances will increase operating costs for Cascade. If Cascade is not able to receive timely and full recovery of compliance costs from its customers, such costs could adversely impact the results of its operations. On September 27, 2016 and September€30, 2016, Cascade and three other natural gas distribution utility companies jointly filed complaints in the United States District Court for the Eastern District of Washington and the Thurston County Superior Court, respectively, asking the courts to deem the rule invalid. The companies asserted that the Washington DOE undertook this rulemaking without the requisite statutory authority. On December 15, 2017, the Thurston County Superior Court vacated the Clean Air Rule and Washington DOE suspended the ruleƒs compliance obligations on December 21, 2017. On May 16, 2018, Washington DOE appealed the lower court ruling to the Supreme Court for the State of Washington and oral argument is scheduled for March 19, 2019. Litigation in the United States District Court for the Eastern District of Washington continues to be held in abeyance.

Treaties, legislation or regulations to reduce GHG emissions in response to climate change may be adopted that affect the Company's utility operations by requiring additional energy conservation efforts or renewable energy sources, limiting emissions, imposing carbon taxes or other compliance costs; as well as other mandates that could significantly increase capital expenditures and operating costs or reduce demand for the Company's utility services. If the Companyƒs utility operations do not receive timely and full recovery of GHG emission compliance costs from customers, then such costs could adversely impact the results of its operations and cash flows. Significant reductions in demand for the Company's utility services as a result of increased costs or emissions limitations could also adversely impact the results of its operations and cash flows.

The Company monitors, analyzes and reports GHG emissions from its other operations as required by applicable laws and regulations. The Company will continue to monitor GHG regulations and their potential impact on 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.

Other Risks

The Company's various businesses are seasonal and subject to weather conditions that can adversely affect the Company's operations, 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 and affect the price of energy commodities. Utility operations have historically generated lower revenues when weather conditions are cooler than normal in the summer and warmer than normal in the winter particularly in jurisdictions that do not have decoupling mechanisms in place. Where decoupling mechanism are in place, there is no assurance the Company will continue to receive such regulatory protection from adverse weather in future rates.

Adverse weather conditions, such as heavy or sustained rainfall or snowfall, storms, wind, and colder weather may affect the demand for products and the ability to perform services at the construction businesses and affect ongoing operation and maintenance and construction activities for the electric and natural gas transmission and distribution businesses. In addition, severe weather can be destructive, causing outages, and/or property damage, which could require additional remediation costs. The Company could also be impacted by drought conditions, which may restrict the availability of water supplies and inhibit the ability of the construction businesses to conduct operations. As a result, unusually mild winters or summers or adverse weather conditions could negatively affect the Company's results of operations, financial position and cash flows.

Competition exists in all of the Company's businesses.
The Company's businesses are subject to 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 competitive forces such as price, service, delivery time and proximity to the customer. The electric utility and natural gas industries also experience competitive pressures as a result of consumer demands, technological advances and other factors. The pipeline and midstream business competes with several pipelines for access to natural gas supplies and for gathering, transportation and storage business. New acquisition opportunities are subject to competitive bidding environments which impacts prices the Company must pay to successfully acquire new properties to grow its business. Competition could negatively affect the Company's results of operations, financial position and cash flows.

The Company's operations may be negatively affected if it is unable to obtain, develop and retain key personnel and skilled labor forces.
The Company must attract, develop and retain executive officers and other professional, technical and skilled labor forces with the skills and experience necessary to successfully manage, operate and grow the Company's businesses. Competition for these employees is high, and in some cases competition for these employees is on a regional or national basis. A shortage in the supply of skilled personnel creates competitive hiring markets and increased labor expenses, decreased productivity and potentially lost business opportunities. Additionally, if the Company is unable to hire employees with the requisite skills, the Company may be forced to incur significant training expenses. As a result, the Company's ability to maintain productivity, relationships with customers, competitive costs, and quality services is limited by the ability to employ the necessary skilled personnel and could negatively affect the Company's results of operations, financial position and cash flows.

The Company's construction materials and contracting and construction services businesses may be exposed to warranty claims.
The Company, particularly its construction businesses, may provide warranties guaranteeing the work performed against defects in workmanship and material. If warranty claims occur, they may require the Company to re-perform the services or to repair or replace the warranted item, at a cost to the Company and could also result in other damages if the Company is not able to adequately satisfy warranty obligations. In addition, the Company may be required under contractual arrangements with customers to warrant any defects or failures in materials the Company purchased from third parties. While the Company generally requires suppliers to provide warranties that are consistent with those the Company provides to customers, if any of the suppliers default on their warranty obligations to the Company, the Company may nonetheless incur costs to repair or replace the defective materials. Costs incurred as a result of warranty claims could adversely affect the Company's results of operations, financial condition and cash flows.

The Company is a holding company and relies on cash from its subsidiaries to pay dividends.
The Company is a holding company as a result of the Holding Company Reorganization. Its investments in its subsidiaries comprise the Company's primary assets. The Company depends on earnings, cash flows and dividends from its subsidiaries to pay dividends on its common stock. The Company's subsidiaries are separate legal entities that have no obligation to pay any amounts due on its obligations or

to make funds available to pay dividends on common stock. Regulatory, contractual and legal limitations, as well as their capital requirements, affect the ability of the subsidiaries to pay dividends to the Company and thereby could restrict or influence the Company's ability or decision to pay dividends on its common stock which could adversely affect the Company's stock price.

Costs related to obligations under MEPPs 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 70€MEPPs 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 30€percent of the MEPPs to which it contributes are currently in endangered, seriously endangered or critical status.

The Company may also be required to increase its contributions to MEPPs if the other participating employers in such plans withdraw from the plans and are not able to contribute amounts sufficient to fund the unfunded liabilities associated with their participation in the plans. The amount and timing of any increase in the Company's required contributions to MEPPs may also depend upon one or more 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; newly-enacted government law or regulations and the actual return on assets held in the plans; among others. The Company could experience increased operating expenses as a result of required contributions to MEPPs, which could 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. The Company could also incur additional withdrawal liability if its withdrawal from a plan is determined by that plan to be part of a mass withdrawal.

Information technology disruptions or cyberattacks could adversely impact the Company's operations.
The Company uses technology in substantially all aspects of its business operations and requires uninterrupted operation of information technology systems and network infrastructure. While the Company has policies, procedures and processes in place designed to strengthen and protect these systems, they may be vulnerable to failures or unauthorized access, including disaster recovery and backup systems, due to hacking, human error, theft, sabotage, malicious software, acts of terrorism, acts of war, acts of nature or other causes. If these systems fail or become compromised, and they are not recovered in a timely manner, the Company may be unable to fulfill critical business functions. This may include interruption of electric generation, transmission and distribution facilities, natural gas storage and pipeline facilities and facilities for delivery of construction materials or other products and services, any of which could have a material adverse effect on the Company's reputation, business, cash flows and results of operations or subject the Company to legal or regulatory liabilities and increased costs.

The Companyƒs accounting systems and its ability to collect information and invoice customers for products and services could also be disrupted. If the Companyƒs operations were disrupted, it could result in decreased revenues or significant remediation costs that have a material adverse effect on the Company's results of operations and cash flows. Additionally, because electric generation and transmission systems and natural gas pipelines are part of interconnected systems with other operatorsƒ facilities, a cyber-related disruption in another operatorƒs system could negatively impact the Company's business.

The Company is subject to cyber security and privacy laws and regulations of many government agencies, including FERC and NERC. NERC issues comprehensive regulations and standards surrounding the security of bulk power systems and is continually in the process of updating these requirements as well as establishing new requirements with which the utility industry must comply. As these regulations evolve, the Company will experience increased compliance costs and be at higher risk for violating these standards. Experiencing a cybersecurity incident could cause the Company to be non-compliant with applicable laws and regulations, causing the Company to incur costs related to legal claims or proceedings and regulatory fines or penalties.

The Company, through the ordinary course of business, requires access to sensitive customer, employee and Company data. While the Company has implemented extensive security measures, a breach of its systems could compromise sensitive data and could go unnoticed for some time. In addition, there has been an increase in the number and sophistication of cyber-attacks across all industries worldwide and the threats are continually evolving. Such an event could result in negative publicity and reputational harm, remediation costs, legal claims and fines that could have an adverse effect on the Company's financial results. Third-party service providers that perform critical business functions for the Company or have access to sensitive information within the Company also may be vulnerable to security breaches and information technology risks that could have an adverse effect on the Company.

The Companyƒs information systems experience on-going and often sophisticated cyber-attacks by a variety of sources with the apparent aim to breach our cyber-defenses. As cyber-attacks continue to increase in frequency and sophistication, the Company may be unable to prevent all such attacks in the future. The Company is continuously reevaluating the need to upgrade and/or replace systems and network infrastructure. These upgrades and/or replacements could adversely impact operations by imposing substantial capital expenditures, creating delays or outages, or experiencing difficulties transitioning to new systems. Systems implementation disruption and any other information technology disruption, if not anticipated and appropriately mitigated, 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 risks to the Company. These other factors may materially negatively 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 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.
- 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 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.
- Losses or costs relating to litigation.
- The inability to effectively integrate the operations and the internal controls of acquired companies.

Item 1B.€Unresolved Staff Comments

The Company has no unresolved comments with the SEC.

Item€3. Legal Proceedings

For information regarding legal proceedings required by this item, 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."

As of December€31, 2018, the Company's common stock was held by approximately 11,300€stockholders of record.

The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. The Company has paid quarterly dividends for more than 80 consecutive years with an increase in the payout amount for the last 28 consecutive years. 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€11.

On June 4, 2018, the Company completed an acquisition in which a portion of the consideration consisted of the unregistered issuance of shares of the Company's common stock. On November 7, 2018, an additional amount of consideration was paid relating to this acquisition, which included 7,662 shares of the Company's common stock with a fair value of approximately $193,000. For additional information about this acquisition, see Item 8 - Note 3. The shares of common stock issued relating to this acquisition were issued in reliance upon the exemption from registration provided by Section 4(a)(2) of the Securities Act, as the shares were issued to the owners of businesses acquired in privately negotiated transactions not involving any public offering or solicitation.

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, 2018	„	„	„	„
November€1 through November€30, 2018	38,605	$26.55	„	„
December€1 through December€31, 2018	„	„	„	„
Total	38,605		„	„

(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.
(2) Not applicable. The Company does not currently have in place any publicly announced plans or programs to purchase equity securities.

Item€6. Selected Financial Data

	2018	2017	2016	2015	2014	2013
Selected Financial Data						
Operating revenues (000's):						
Electric	$ 335,123	$ 342,805	$ 322,356	$ 280,615	$ 277,874	$ 257,260
Natural gas distribution	823,247	848,388	766,115	817,419	921,986	851,945
Pipeline and midstream	128,923	122,213	141,602	154,904	157,292	144,568
Construction materials and contracting	1,925,854	1,812,529	1,874,270	1,904,282	1,765,330	1,712,137
Construction services	1,371,453	1,367,602	1,073,272	926,427	1,119,529	1,039,839
Other	11,259	7,874	8,643	9,191	9,364	9,620
Intersegment eliminations	(64,307)	(58,060)	(57,430)	(78,786)	(136,302)	(95,201)
	$ 4,531,552	$ 4,443,351	$ 4,128,828	$ 4,014,052	$ 4,115,073	$ 3,920,168
Operating income (loss) (000's):						
Electric	$ 65,148	$ 79,902	$ 67,929	$ 59,915	$ 61,515	$ 54,386
Natural gas distribution	72,336	84,239	66,166	54,974	68,185	79,910
Pipeline and midstream	36,128	36,004	42,864	30,218	46,500	20,070
Construction materials and contracting	141,426	143,230	178,753	148,312	87,243	92,037
Construction services	86,764	81,292	53,546	43,678	82,408	85,242
Other	(79)	(619)	(349)	(8,414)	(5,370)	(4,384)
Intersegment eliminations	•	„	„	(2,942)	(9,900)	(7,176)
	$ 401,723	$ 424,048	$ 408,909	$ 325,741	$ 330,581	$ 320,085
Earnings (loss) on common stock (000's):						
Electric	$ 47,000	$ 49,366	$ 42,222	$ 35,914	$ 36,731	$ 34,837
Natural gas distribution	37,732	32,225	27,102	23,607	30,484	37,656
Pipeline and midstream	28,459	20,493	23,435	13,250	24,666	7,701
Construction materials and contracting	92,647	123,398	102,687	89,096	51,510	50,946
Construction services	64,309	53,306	33,945	23,762	54,432	52,213
Other	(761)	(1,422)	(3,231)	(14,941)	(7,386)	(10,776)
Intersegment eliminations	•	6,849	6,251	5,016	(6,095)	(4,307)
Earnings on common stock before income (loss) from discontinued operations	269,386	284,215	232,411	175,704	184,342	168,270
Income (loss) from discontinued operations, net of tax*	2,932	(3,783)	(300,354)	(834,080)	109,311	109,615
Loss from discontinued operations attributable to noncontrolling interest	•	„	(131,691)	(35,256)	(3,895)	(363)
	$ 272,318	$ 280,432	$ 63,748	$ (623,120)	$ 297,548	$ 278,248
Earnings per common share before discontinued operations - diluted	$ 1.38	$ 1.45	$ 1.19	$ .90	$ .96	$ .89
Discontinued operations attributable to the Company, net of tax	.01	(.02)	(.86)	(4.10)	.59	.58
	$ 1.39	$ 1.43	$ .33	$ (3.20)	$ 1.55	$ 1.47
Common Stock Statistics						
Weighted average common shares outstanding€-diluted (000's)	196,150	195,687	195,618	194,986	192,587	189,693
Dividends declared per common share	$ .7950	$ .7750	$ .7550	$ .7350	$ .7150	$ .6950
Book value per common share	$ 13.09	$ 12.44	$ 11.78	$ 12.83	$ 16.66	$ 15.01
Market price per common share (year end)	$ 23.84	$ 26.88	$ 28.77	$ 18.32	$ 23.50	$ 30.55
Market price ratios:						
Dividend payout**	58%	53%	63%	82%	74%	78%
Yield	3.4%	2.9%	2.7%	4.1%	3.1%	2.3%
Market value as a percent of book value	182.1%	216.1%	244.2%	142.8%	141.1%	203.5%

* Reflects oil and natural gas properties noncash write-downs of $315.3 million (after tax) in 2015 and fair value impairments of assets held for sale of $157.8 million (after tax) and $475.4€million (after tax) in 2016 and 2015, respectively.

** Based on continuing operations.

Item 6. Selected Financial Data (continued)

	2018	2017	2016	2015	2014	2013
General						
Total assets (000's)	$ 6,988,110	$ 6,334,666	$ 6,284,467	$ 6,565,154	$ 7,805,405	$ 7,043,365
Total long-term debt (000's)	$ 2,108,695	$ 1,714,853	$ 1,790,159	$ 1,796,163	$ 2,016,198	$ 1,773,050
Capitalization ratios:						
Total equity	55%	59%	56%	58%	62%	62%
Total debt	45	41	44	42	38	38
	100%	100%	100%	100%	100%	100%
Electric						
Retail sales (thousand kWh)	3,354,401	3,306,470	3,258,537	3,316,017	3,308,358	3,173,086
Electric system summer and firm purchase contract ZRCs (Interconnected system)	574.5	553.1	559.7	547.3	584.0	583.5
Electric system peak demand obligation, including firm purchase contracts, planning reserve margin requirement (Interconnected€system)	537.2	530.2	559.7	547.3	522.4	508.3
All-time demand peak - kW (Interconnected€system)	611,542	611,542	611,542	611,542	582,083	573,587
Electricity produced (thousand kWh)	2,840,353	2,630,640	2,626,763	1,898,160	2,519,938	2,430,001
Electricity purchased (thousand€kWh)	831,039	955,687	904,702	1,658,002	1,010,422	971,261
Average cost of electric fuel and purchased power per kWh	$ .022	$ .022	$ .021	$ .024	$ .025	$ .025
Natural Gas Distribution						
Sales (Mdk)	112,566	112,551	99,296	95,559	104,297	108,260
Transportation (Mdk)	149,497	144,477	147,592	154,225	145,941	149,490
Pipeline and Midstream						
Transportation (Mdk)	351,498	312,520	285,254	290,494	233,483	178,598
Gathering (Mdk)	14,882	16,064	20,049	33,441	38,372	40,737
Customer natural gas storage balance (Mdk)	13,928	22,397	26,403	16,600	14,885	26,693
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	29,795	28,213	27,580	26,959	25,827	24,713
Asphalt (tons)	6,838	6,237	7,203	6,705	6,070	6,228
Ready-mixed concrete (cubic€yards)	3,518	3,548	3,655	3,592	3,460	3,223
Aggregate reserves (000's tons)	1,014,431	965,036	989,084	1,022,513	1,061,156	1,083,376

Item€7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The Company operates with a two-platform business model. Its regulated energy delivery platform and its construction materials and services platform are each comprised of different operating segments. Some of these segments experience seasonality related to the industries in which they operate. The two-platform approach helps balance this seasonality and the risk associated with each type of industry. Through its regulated energy delivery platform, the Company provides electric and natural gas services to customers, generates, transmits and distributes electricity, and provides natural gas transportation, storage and gathering services. These businesses are regulated by state public service commissions and/or the FERC. The construction materials and services platform provides construction services to a variety of industries, including commercial, industrial and governmental, and provides construction materials through aggregate mining and marketing of related products, such as ready-mixed concrete and asphalt.

The Company is organized into five reportable business segments. These business segments include: electric, natural gas distribution, pipeline and midstream, construction materials and contracting, and construction services. The Company's business segments are determined 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 segments is defined based on the reporting and review process used by the Company's chief executive officer.

The Company's strategy is to apply its expertise in the regulated energy delivery and construction materials and services businesses to increase market share, increase profitability and enhance shareholder value through organic growth opportunities and strategic acquisitions. The Company is focused on a disciplined approach to the acquisition of well-managed companies and properties.

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 capital expenditures, see Liquidity and Capital Commitments.

On December 22, 2017, President Trump signed into law the TCJA making significant changes to the United States federal income tax laws. Some of the more material changes from the TCJA that impacted the Company were reduced corporate tax rates, repeal of the domestic production deduction and disallowance of immediate expensing for regulated utility property. The Company has reviewed the impacts of the TCJA and is complying with all known tax rules and guidance. For additional information on the impacts of the TCJA, see Item 8 - Note 13.

Consolidated Earnings Overview

The following table summarizes the contribution to the consolidated earnings by each of the Company's business segments.

Years ended December€31,	2018	2017	2016
	(In millions, except per share amounts)		
Electric	$ 47.0	$ 49.4	$ 42.2
Natural gas distribution	37.7	32.2	27.1
Pipeline and midstream	28.5	20.5	23.4
Construction materials and contracting	92.6	123.4	102.7
Construction services	64.3	53.3	33.9
Other	(.7)	(1.5)	(3.2)
Intersegment eliminations	•	6.9	6.3
Earnings before discontinued operations	269.4	284.2	232.4
Income (loss) from discontinued operations, net of tax	2.9	(3.8)	(300.4)
Loss from discontinued operations attributable to noncontrolling interest	•	„	(131.7)
Earnings on common stock	$ 272.3	$ 280.4	$ 63.7
Earnings per common share - basic:			
Earnings before discontinued operations	$ 1.38	$ 1.46	$ 1.19
Discontinued operations attributable to the Company, net of tax	.01	(.02)	(.86)
Earnings per common share - basic	$ 1.39	$ 1.44	$ .33
Earnings per common share - diluted:			
Earnings before discontinued operations	$ 1.38	$ 1.45	$ 1.19
Discontinued operations attributable to the Company, net of tax	.01	(.02)	(.86)
Earnings per common share - diluted	$ 1.39	$ 1.43	$ .33

2018 compared to 2017 The Company's consolidated earnings decreased $8.1 million.

The Company's earnings were positively impacted in 2018 as a result of the lower federal statutory tax rate, which was partially offset by the absence of a $39.5 million tax benefit recorded in the fourth quarter of 2017 for the revaluation of the business's net deferred tax liabilities. Both tax impacts were the result of the enactment of the TCJA, as further discussed in Item 8 - Note 13. Decreased earnings due to lower returns on investments also offset the lower income tax rate. Also positively impacting the Company's earnings were higher outside specialty contracting gross margins due to increased outside equipment sales and rentals at the construction services business, as well as a $4.2 million income tax benefit relating to the reversal of a regulatory liability recorded in 2017 based on a FERC final accounting order issued during the third quarter of 2018 at the pipeline and midstream business.

2017 compared to 2016 The Company's consolidated earnings increased $216.7 million.

The Company's earnings were positively impacted due to the absence in 2017 of a loss associated with the sale of the refining business in June 2016 relating to discontinued operations, as well as an overall income tax benefit to the Company of $39.5 million primarily for the revaluation of the Company's net deferred tax liabilities. Also contributing to the Company's increased earnings were higher inside and outside specialty contracting margins driven by decreased costs and higher contracting workloads at the construction services business, higher natural gas retail sales margins as a result of increased retail sales volumes at the natural gas distribution business and higher electric retail sales margins at the electric business. These increases were partially offset by lower asphalt product and construction margins driven by competitive pricing and unfavorable weather at the construction materials and contracting business and lower gathering and processing revenues resulting from lower volumes due to the sale of the Pronghorn assets in January 2017 at the pipeline and midstream business.

A discussion of key financial data from the Company's business segments follows.

Business Segment Financial and Operating Data

Following are key financial and operating data for each of the Company's business segments. Also included are highlights on key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters of the Company's business segments. Many of these highlighted points are "forward-looking statements." For more information, see Part I - 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.

For information pertinent to various commitments and contingencies, see Item 8 - Notes to Consolidated Financial Statements. For a summary of the Company's business segments, see Item 8 - Note 15.

Electric and Natural Gas Distribution

Strategy and challenges The electric and natural gas distribution segments provide electric and natural gas distribution services to customers, as discussed in Items 1 and 2 - Business Properties. Both segments strive to be a top performing utility company measured by integrity, safety, employee satisfaction, customer service and shareholder return, while continuing to focus on providing safe, reliable and competitively priced energy and related services to customers. The Company continues to monitor opportunities for these segments to retain, grow and expand their customer base through extensions of existing operations, including building and upgrading electric generation, transmission and distribution and natural gas systems, and through selected acquisitions of companies and properties at prices that will provide stable cash flows and an opportunity to earn a competitive return on investment. The continued efforts to create operational improvements and efficiencies across both segments promotes the Company's business integration strategy. The primary factors that impact the results of these segments are the ability to earn authorized rates of return, the cost of natural gas, cost of electric fuel and purchased power, weather, competitive factors in the energy industry, population growth and economic conditions in the segments' service areas.

The electric and natural gas distribution segments are subject to extensive regulation in the jurisdictions where they conduct operations with respect to costs, timely recovery of investments and permitted returns on investment, as well as certain operational, system integrity and environmental regulations. To assist in the reduction of regulatory lag with the increase in investments, tracking mechanisms have been implemented in certain jurisdictions. Legislative and regulatory initiatives to increase renewable energy resources and reduce GHG emissions could impact the price and demand for electricity and natural gas and result in the retirement of certain electric generating facilities before they are fully depreciated. Although the current administration has slowed environmental regulations, the segments continue to invest in facility upgrades to be in compliance with the existing and future regulations.

Tariff increases on steel and aluminum materials could negatively affect the segments' construction projects and maintenance work. The Company continues to monitor the impact tariff increases will have on raw material costs. The natural gas distribution segment is also facing increased lead times on delivery of certain raw materials used in pipeline projects. In addition to the effect of tariffs, long lead times are attributable to increased demand for steel products from pipeline companies as they respond to the United States Department of Transportation Pipeline System Safety and Integrity Plan. The Company continues to monitor the material lead times and is working with manufacturers to proactively order such materials to help mitigate the extended lead times.

The ability to grow through acquisitions is subject to significant competition and acquisition premiums. In addition, the ability of the segments to grow their 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 is subject to increasing cost and lead time, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which will likely necessitate increases in electric energy prices.

Revenues are impacted by both customer growth and usage, the latter of which is primarily impacted by weather. Very cold winters increase demand for natural gas and to a lesser extent, electricity, while warmer than normal summers increase demand for electricity, especially among residential and commercial customers. Average consumption among natural gas customers has tended to decline as more efficient appliances and furnaces are installed, and as the Company has implemented conservation programs. Natural gas decoupling mechanisms in certain jurisdictions have been implemented to largely mitigate the effect that would otherwise be caused by variations in volumes sold to these customers due to weather and changing consumption patterns on the Company's distribution margins.

Earnings overview - The following information summarizes the performance of the electric segment.

Years ended December 31,	2018	2017	2016
	(Dollars in millions, where applicable)		
Operating revenues	$ 335.1	$ 342.8	$ 322.3
Electric fuel and purchased power	80.7	78.7	75.5
Taxes, other than income	.7	.8	.6
Adjusted gross margin	253.7	263.3	246.2
Operating expenses:			
Operation and maintenance	123.0	122.2	115.8
Depreciation, depletion and amortization	51.0	47.7	50.2
Taxes, other than income	14.5	13.5	12.3
Total operating expenses	188.5	183.4	178.3
Operating income	65.2	79.9	67.9
Other income	1.2	3.2	1.3
Interest expense	25.9	25.4	25.0
Income before income taxes	40.5	57.7	44.2
Income taxes	(6.5)	7.7	1.4
Net income	47.0	50.0	42.8
Loss/dividends on preferred stock	•	.6	.6
Earnings	$ 47.0	$ 49.4	$ 42.2
Retail sales (million kWh):			
Residential	1,196.6	1,153.5	1,132.5
Commercial	1,513.9	1,513.1	1,491.8
Industrial	551.0	539.9	544.2
Other	92.9	100.0	90.0
	3,354.4	3,306.5	3,258.5
Average cost of electric fuel and purchased power per kWh	$ .022	$ .022	$ .021

Adjusted gross margin is a non-GAAP financial measure. For additional information and reconciliation of the non-GAAP adjusted gross margin attributable to the electric segment, see the Non-GAAP Financial Measures section later in this Item.

2018 compared to 2017 Electric earnings decreased $2.4 million (5 percent) as a result of:

Adjusted gross margin: Decrease of $9.6 million, primarily due to lower operating revenues driven by the reserves against revenues in certain jurisdictions for anticipated refunds to customers for lower income taxes due to the enactment of TCJA and a transmission formula rate adjustment due to lower than anticipated project costs on the BSSE project recorded in the third quarter of 2018. Partially offsetting the decreases to adjusted gross margin were the absence in 2018 of reserves related to tracker balances in prior years and increased retail sales volumes of 1 percent to all major customer classes.

Operation and maintenance: Increase of $800,000, largely from higher contract services at certain generating stations. Partially offsetting the increase were lower payroll-related costs.

Depreciation, depletion and amortization: Increase of $3.3 million as a result of increased plant balances.

Taxes, other than income: Increase of $1.0 million, primarily from higher property taxes in certain jurisdictions.

Other income: Decrease of $2.0 million, largely the result of lower returns on investments.

Interest expense: Comparable to the prior year.

Income taxes: Decrease of $14.2 million, largely due to the enactment of the TCJA reduced corporate tax rate, reduced income before income taxes and the absence of $2.1 million of income tax expense in 2018 for the revaluation of nonutility net deferred tax assets in 2017, as discussed in Item 8 - Note 13. Partially offsetting these decreases were lower production tax credits. A portion of the reduction in income taxes are being reserved against revenues, as previously discussed, resulting in a minimal impact on overall earnings.

2017 compared to 2016 Electric earnings increased $7.2 million (17 percent) as a result of:

Adjusted gross margin: Increase of $17.1 million, primarily from increased electric retail sales margins from the recovery of an additional investment on the BSSE project, approved rate recovery in all jurisdictions and 2 percent higher retail sales volumes to commercial and residential customers.

Operation and maintenance: Increase of $6.4 million, largely from higher payroll-related costs, material costs and contract services at certain generating stations.

Depreciation, depletion and amortization: Decrease of $2.5 million, largely from lower depreciation rates implemented in conjunction with regulatory recovery activity.

Taxes, other than income: Increase of $1.2 million, primarily from higher property taxes in certain jurisdictions.

Other income: Increase of $1.9 million, largely the result of higher returns on investments.

Interest expense: Comparable to the prior year.

Income taxes: Increase of $6.3 million, largely from increased income before income taxes and $2.1 million of income tax expense for the revaluation of nonutility net deferred tax assets, as discussed in Item 8 - Note 13.

Earnings overview - The following information summarizes the performance of the natural gas distribution segment.

Years ended December 31,	2018	2017	2016
	(Dollars in millions, where applicable)		
Operating revenues	$ 823.2	$ 848.4	$ 766.1
Purchased natural gas sold	454.8	479.9	431.5
Taxes, other than income	28.5	30.0	26.5
Adjusted gross margin	339.9	338.5	308.1
Operating expenses:			
Operation and maintenance	173.4	164.3	156.9
Depreciation, depletion and amortization	72.5	69.4	65.4
Taxes, other than income	21.7	20.5	19.6
Total operating expenses	267.6	254.2	241.9
Operating income	72.3	84.3	66.2
Other income	.2	2.0	.6
Interest expense	30.7	31.2	30.4
Income before income taxes	41.8	55.1	36.4
Income taxes	4.1	22.8	9.2
Net income	37.7	32.3	27.2
Loss/dividends on preferred stock	•	.1	.1
Earnings	$ 37.7	$ 32.2	$ 27.1
Volumes (MMdk)			
Retail sales:			
Residential	63.7	63.6	56.2
Commercial	44.4	44.3	38.9
Industrial	4.5	4.6	4.2
	112.6	112.5	99.3
Transportation sales:			
Commercial	2.2	2.0	1.8
Industrial	147.3	142.5	145.8
	149.5	144.5	147.6
Total throughput	262.1	257.0	246.9
Average cost of natural gas, including transportation, per dk	$ 4.04	$ 4.26	$ 4.35

Adjusted gross margin is a non-GAAP financial measure. For additional information and reconciliation of the non-GAAP adjusted gross margin attributable to the natural gas distribution segment, see the Non-GAAP Financial Measures section later in this Item.

2018 compared to 2017 Natural gas distribution earnings increased $5.5 million (17 percent) as a result of:

Adjusted gross margin: Increase of $1.4 million, primarily due to increased retail sales margins, mainly the result of weather normalization mechanisms in certain jurisdictions and conservation revenue, which offsets the conservation expense in operation and maintenance expense. Also contributing to the retail sales margin increase were higher basic service charges as a result of increased retail sales customers and rate design. These increases were partially offset by tax reform revenue impacts for refunds to customers as a result of lower income taxes due to the enactment of TCJA and lower volumes in certain jurisdictions.

Operation and maintenance: Increase of $9.1 million, largely related to conservation expenses being recovered in revenue; contract services, which includes the recognition of a non-recurring expense related to the approved WUTC general rate case settlement in the second quarter 2018; and higher payroll-related costs.

Depreciation, depletion and amortization: Increase of $3.1 million, primarily as a result of increased plant balances offset in part by lower depreciation rates implemented in certain jurisdictions.

Taxes, other than income: Increase of $1.2 million due to higher property taxes in certain jurisdictions.

Other income: Decrease of $1.8 million, primarily the result of lower returns on investments.

Interest expense: Comparable to the prior year.

Income taxes: Decrease of $18.7 million, largely due to the enactment of the TCJA reduced corporate tax rate, as well as the absence of $4.3 million income tax expense related to the 2017 revaluation of nonutility net deferred tax assets, as discussed in Item 8 - Note 13, and reduced income before income taxes. A portion of the reduction in income taxes are being reserved against revenues or passed back to customers, as previously discussed, resulting in a minimal impact on overall earnings.

2017 compared to 2016 Natural gas distribution earnings increased $5.1 million (19 percent) as a result of:

Adjusted gross margin: Increase of $30.4 million, primarily due to increased retail sales margins as a result of increased retail sales volumes of 13 percent across all customer classes from colder weather in all jurisdictions, offset in part by weather normalization in certain jurisdictions and 2 percent customer growth. Also contributing to the increases were approved final and interim rate increases.

Operation and maintenance: Increase of $7.4 million, primarily from increased payroll-related costs and material costs.

Depreciation, depletion and amortization: Increase of $4.0 million as a result of increased plant balances.

Taxes, other than income: Increase of $900,000 due to higher property taxes in certain jurisdictions.

Other income: Increase of $1.4 million as a result of higher returns on investments.

Interest expense: Increase of $800,000 due to increased debt balances.

Income taxes: Increase of $13.6 million, largely the result of increased income before income taxes, as well as an additional $4.3 million income tax expense for the revaluation of nonutility net deferred tax assets, as discussed in Item 8 - Note 13.

Outlook The Company expects these segments will grow rate base by approximately 5 percent annually over the next five years on a compound basis. This growth projection is on a much larger base, having grown rate base at a record pace of 12 percent compounded annually over the past five-year period. Operations are spread across eight states where the Company expects customer growth to be higher than the national average. The Company expects its customer base to grow by 1 percent to 2 percent per year. This customer growth, along with system upgrades and replacements needed to supply safe and reliable service, will require investments in new electric generation and transmission and natural gas systems.

In November 2017, the NDPSC approved the advance determination of prudence for the purchase of the Thunder Spirit Wind farm expansion in southwest North Dakota. Construction of the Thunder Spirit Wind farm expansion began in May 2018 and on October 31, 2018, the Company finalized the purchase and placed it into service. With the addition of the expansion, the total Thunder Spirit Wind farm generation capacity is approximately 155 MW and increased the Company's electric generation portfolio to approximately 27 percent renewables based on nameplate ratings. The Company's integrated resource plans filed in North Dakota and Montana in 2017 include additional generation projects in the 2025 timeframe.

In June 2016, the Company, along with a partner, began construction on the BSSE project. The estimated capital investment for this project has been updated to approximately $130 million. All necessary easements have been secured and construction is complete. The Company began bringing the project on-line on February 5, 2019. In addition, the Company is also expecting to receive a continuation of the return on the project throughout the year.

On February 19, 2019, the Company announced that it intends to retire three aging coal-fired electric generation units within the next three years due to the fact that the plants are no longer expected to be cost competitive. The retirements are expected to be in late 2020 for Lewis & Clark station in Sidney, Montana, and in late 2021 for units 1 and 2 at Heskett station in Mandan, North Dakota. These dates may be impacted by the Company's coal supplier's pending bankruptcy proceeding. In addition, the Company announced that it intends to construct a new simple-cycle natural gas combustion turbine peaking unit at the existing plant site in Mandan, North Dakota.

The Company continues to be focused on the regulatory recovery of its investments. Since January 1, 2018, these segments have implemented rate increases, as well as system integrity mechanisms, in Minnesota, Montana, North Dakota, Washington and before the FERC. The Company files for rate adjustments to seek recovery of operating costs and capital investments, as well as reasonable returns as allowed by regulators. The Company's most recent cases by jurisdiction are discussed in Item 8 - Note 18.

With the enactment of the TCJA, the state regulators in jurisdictions where the segments operate requested companies submit plans for the estimated impact of the TCJA. The segments determined the use of the deferral method of accounting for the revaluation of its regulated deferred tax assets and liabilities was appropriate. As such, the Company recorded a regulatory liability for the excess deferred income taxes that related to the effect of the change in tax rates on its regulated deferred tax assets and liabilities in the fourth quarter of 2017. For the twelve months ended December 31, 2018, the Company reserved an additional regulatory liability of approximately $18.5 million, which is an offset to the Company's revenues, as previously discussed. The additional reserves were calculated by completing a revenue requirement calculation in each state where the Company thought it was probable that the refund of tax savings would be returned to the Company's customers, or based on calculations or amounts prescribed by the commissions. The Company has been working on various rate cases with the state regulators relating to the impacts of the TCJA. A majority of these rate cases have been settled with new rates being implemented in 2018 or upcoming in 2019. For further details on the status of implementing the new rates, as well as the status on open rate cases, see

Item 8 - Note 18. Due to not being able to immediately expense utility property for tax purposes, the segments' cash flows are negatively impacted.

Pipeline and Midstream

Strategy and challenges The pipeline and midstream segment provides natural gas transportation, gathering and underground storage services, as discussed in Items 1 and 2 - Business Properties. The segment focuses on utilizing its extensive expertise in the design, construction and operation of energy infrastructure and related services to increase market share and profitability through optimization of existing operations, organic growth and investments in energy-related assets within or in close proximity to its current operating areas. The segment focuses on the continual safety and reliability of its systems, which entails building and maintaining safe natural gas pipelines and facilities. The segment continues to evaluate growth opportunities including the expansion of existing storage, gathering and transmission facilities; incremental pipeline projects to expand pipeline capacity; and expansion of energy-related services leveraging on its core competencies.

The segment is exposed to energy price volatility which is impacted by the fluctuations in pricing, production and basis differentials of the energy market's commodities. Legislative and regulatory initiatives to increase pipeline safety regulations and reduce methane emissions could also impact the price and demand for natural gas.

Tariff increases on steel and aluminum materials could negatively affect the segment's construction projects and maintenance work. The Company continues to monitor the impact tariff increases will have on raw material costs. The segment experiences extended lead times on raw materials that are critical to the segment's construction and maintenance work. Long lead times on materials could delay maintenance work and project construction potentially causing lost revenues and/or increased costs. The Company continues to proactively monitor and plan for the material lead times, as well as work with manufacturers and suppliers to help mitigate the extended lead times.

The pipeline and midstream segment is subject to extensive regulation including certain operational, system integrity and environmental regulations, as well as various permit terms and operational compliance conditions. The segment is charged with the ongoing process of reviewing existing permits and easements, as well as securing new permits and easements as necessary to meet current demand and future growth opportunities. Exposure to pipeline opposition groups could also cause negative impacts on the segment with increased costs and potential delays to project completion.

The segment focuses on the recruitment and retention of a skilled workforce to remain competitive and provide services to its customers. The industry in which it operates relies on a skilled workforce to construct energy infrastructure and operate existing infrastructure in a safe manner. A shortage of skilled personnel can create a competitive labor market which could increase costs incurred by the segment. Competition from other pipeline and midstream companies can also have a negative impact on the segment.

Earnings overview The following information summarizes the performance of the pipeline and midstream segment.

Years ended December 31,		2018		2017		2016
		(Dollars in millions)				
Operating revenues	$	128.9	$	122.2	$	141.6
Operating expenses:						
Operation and maintenance		62.2		56.9		61.9
Depreciation, depletion and amortization		17.9		16.8		24.9
Taxes, other than income		12.7		12.5		11.9
Total operating expenses		92.8		86.2		98.7
Operating income		36.1		36.0		42.9
Other income		1.0		1.8		.9
Interest expense		5.9		5.0		8.0
Income before income taxes		31.2		32.8		35.8
Income taxes		2.7		12.3		12.4
Earnings	$	28.5	$	20.5	$	23.4
Transportation volumes (MMdk)		351.5		312.5		285.3
Natural gas gathering volumes (MMdk)		14.9		16.1		20.0
Customer natural gas storage balance (MMdk):						
Beginning of period		22.4		26.4		16.6
Net injection (withdrawal)		(8.5)		(4.0)		9.8
End of period		13.9		22.4		26.4

2018 compared to 2017 Pipeline and midstream earnings increased $8.0 million (39 percent) as a result of:

Revenues: Increase of $6.7 million, largely attributable to increased volumes of natural gas transported through its system as a result of completed organic growth projects and higher nonregulated project workloads, which increased revenues $4.1 million. These increases were partially offset by decreased storage-related revenues reflecting the decrease in natural gas pricing spreads, as discussed in the Outlook section.

Operation and maintenance: Increase of $5.3 million, primarily from higher nonregulated project costs of $3.9 million directly related to the increase in nonregulated project workloads, as previously discussed, as well as higher professional services, material costs and contract services.

Depreciation, depletion and amortization: Increase of $1.1 million, largely resulting from organic growth projects.

Taxes, other than income: Comparable to the prior year.

Other income: Decrease of $800,000, primarily the result of lower returns on investments partially offset by higher AFUDC.

Interest expense: Increase of $900,000, largely resulting from higher debt balances.

Income taxes: Decrease of $9.6 million, primarily resulting from the lower corporate tax rate due to the enactment of the TCJA creating a reduction to income tax expense, as well as the realization of a $4.2 million income tax benefit related to the reversal of a regulatory liability recorded in 2017 based on a FERC final accounting order issued during third quarter of 2018.

2017 compared to 2016 Pipeline and midstream earnings decreased $2.9 million (13 percent) as a result of:

Revenues: Decrease of $19.4 million, largely resulting from lower gathering and processing revenues of $22.6 million. The decrease in revenues resulted from lower volumes from the sale of the Pronghorn assets in January 2017. Partially offsetting the decrease was higher transportation revenues of $1.6 million, largely from increased off-system transportation volumes due to organic growth projects completed in 2017.

Operation and maintenance: Decrease of $5.0 million, which includes $3.6 million primarily from the absence of Pronghorn, as previously discussed, and the absence in 2017 of a fair value impairment in 2016 associated with the Pronghorn sale.

Depreciation, depletion and amortization: Decrease of $8.1 million, largely due to the absence of the Pronghorn assets, as previously discussed.

Taxes, other than income: Increase of $600,000 from higher property taxes.

Other income: Increase of $900,000 attributable to higher AFUDC.

Interest expense: Decrease of $3.0 million due to lower debt balances.

Income taxes: Comparable to the prior year.

Outlook The Company has continued to experience the effects of natural gas production at record levels, which has provided opportunities for organic growth projects and increased demand. The completion of organic growth projects has contributed to the Company transporting increasing volumes of natural gas through its system. Additionally, the record levels of natural gas supply have moderated the need for storage services and put downward pressure on natural gas prices and minimized pricing volatility. Both natural gas production levels and pressure on natural gas prices are expected to continue in the near term. The Company continues to focus on growth and improving existing operations through organic projects in all areas in which it operates. The following describes recent growth projects.

In January 2019, the Company announced plans to construct approximately 67 miles of new pipeline, compression and ancillary facilities to transport natural gas from core Bakken production areas near Tioga, North Dakota, and extend to a new interconnection point in McKenzie County, North Dakota. This North Bakken Expansion project, as designed, would provide 200 MMcf per day of natural gas transportation capacity. Construction is expected to begin in early 2021 with an estimated completion date late in 2021, which is dependent on regulatory and environmental permitting and finalization of transportation agreements with customers. The estimated cost of the project is approximately $220€million.

In November 2018, the Company completed construction and placed into service its Valley Expansion project, a 38-mile pipeline that delivers natural gas supply to eastern North Dakota and far western Minnesota. The project, which is designed to transport 40 MMcf of natural gas per day, is under the jurisdiction of the FERC.

In September 2018, the Company completed construction and placed into service its Line Section 27 Expansion project in the Bakken area of northwestern North Dakota. The project includes approximately 13 miles of new pipeline and associated facilities and increases capacity by over 200 MMcf per day. The project brings the total capacity of Line Section 27 to over 600 MMcf per day.

In early 2018, the Company announced two additional natural gas pipeline growth projects, the Demicks Lake project and Line Section 22 Expansion project. The Company has signed long-term commitment contracts supporting both projects. The Demicks Lake project, which includes approximately 14 miles of 20-inch pipe and will increase capacity by 175 MMcf per day, is located in McKenzie County, North Dakota. Construction is expected to begin in 2019, with an in-service date in the fall of 2019. The Line Section 22 Expansion project in the Billings, Montana, area is also scheduled to begin construction in 2019, with an expected in-service date in late 2019. This project will increase capacity by 22.5 MMcf per day to serve incremental demand in Billings, Montana.

Construction Materials and Contracting

Strategy and challenges The construction materials and contracting segment provides an integrated set of construction services, as discussed in Items 1 and 2 - Business Properties. The segment focuses on high-growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; strengthening the long-term, strategic aggregate reserve position through available purchase and/or lease opportunities; enhancing profitability through cost containment, margin discipline and vertical integration of the segment's operations; development and recruitment of talented employees; and continued growth through organic and acquisition opportunities.

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 segment's expertise. The Company's acquisitions in 2018 support this strategy.

As one of the country's largest sand and gravel producers, the segment continues to strategically manage its 1.0 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated. The segment's 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. The Company's aggregate reserves are naturally declining and as a result, the Company seeks acquisition opportunities to replace the reserves. In 2018, the Company's aggregate reserves increased by nearly 50€million tons primarily due to acquisition activity.

The construction materials and contracting segment faces challenges that are not under the direct control of the business. The segment operates in geographically diverse and highly competitive markets. Competition can put negative pressure on the segment's operating margins. The segment is also subject to volatility in the cost of raw materials such as diesel fuel, gasoline, liquid asphalt, cement and steel. Although it is difficult to determine the split between inflation and supply/demand increases, diesel fuel costs remained fairly stable for the past twelve months, while asphalt oil costs have trended higher in 2018 as compared to 2017. Such volatility can have a negative impact on the segment's margins. Other variables that can impact the segment's margins include adverse weather conditions, the timing of project starts or completion and declines or delays in new and existing projects due to the cyclical nature of the construction industry and federal infrastructure spending.

The segment also faces challenges in the recruitment and retention of employees. Trends in the labor market include an aging workforce and availability issues. The segment continues to face increasing pressure to control costs, as well as find and train a skilled workforce to meet the needs of increasing demand and seasonal work.

Earnings overview The following information summarizes the performance of the construction materials and contracting segment.

Years ended December 31,	2018	2017	2016
		(Dollars in millions)	
Operating revenues	$ 1,925.9	$ 1,812.5	$ 1,874.3
Cost of sales:			
Operation and maintenance	1,601.7	1,500.1	1,533.2
Depreciation, depletion and amortization	59.0	52.5	54.1
Taxes, other than income	39.7	38.0	37.5
Total cost of sales	1,700.4	1,590.6	1,624.8
Gross margin	225.5	221.9	249.5
Selling, general and administrative expense:			
Operation and maintenance	77.6	71.5	62.2
Depreciation, depletion and amortization	2.2	3.4	4.3
Taxes, other than income	4.3	3.8	4.3
Total selling, general and administrative expense	84.1	78.7	70.8
Operating income	141.4	143.2	178.7
Other income (expense)	(3.1)	.4	(.1)
Interest expense	17.3	14.8	15.3
Income before income taxes	121.0	128.8	163.3
Income taxes	28.4	5.4	60.6
Earnings	$ 92.6	$ 123.4	$ 102.7
Sales (000's):			
Aggregates (tons)	29,795	28,213	27,580
Asphalt (tons)	6,838	6,237	7,203
Ready-mixed concrete (cubic yards)	3,518	3,548	3,655

2018 compared to 2017 Construction materials and contracting's earnings decreased $30.8 million (25 percent) as a result of:

Revenues: Increase of $113.4 million driven by higher asphalt product and aggregate volumes due to increased agency demand, increased realized prices and lower material costs. Partially offsetting these increases were lower ready-mixed concrete volumes due to a decrease in available work and unfavorable weather conditions in certain regions.

Gross margin: Increase of $3.6 million resulting from higher asphalt product volumes and margins, largely from recent acquisitions and higher realized prices. Also contributing to the increase were higher aggregate volumes and margins due to strong market demand and lower material costs. Partially offsetting these increases were lower ready-mixed concrete volumes and margins due to a decrease in available work and unfavorable weather conditions in certain regions.

Selling, general and administrative expense: Increase of $5.4 million, primarily payroll-related costs, acquisition costs and higher insurance-related costs.

Other income: Decrease of $3.5 million, largely the result of lower returns on investments.

Interest expense: Increase of $2.5 million, largely resulting from higher debt balances as a result of recent acquisitions, capital expenditures and higher working capital needs.

Income taxes: Increase of $23.0 million, primarily resulting from the absence in 2018 of a $41.9 million tax benefit recorded in the fourth quarter of 2017 for the revaluation of the segment's net deferred tax liabilities, as discussed in Item 8 - Note 13. Partially offsetting this increase were lower income taxes due to the enactment of the TCJA, which reduced the corporate tax rate.

2017 compared to 2016 Construction materials and contracting's earnings increased $20.7 million (20 percent) as a result of:

Revenues: Decrease of $61.8 million resulting from lower asphalt product volumes driven by competitive pricing and unfavorable weather during the first half of the year, less available work and increased competition in certain regions.

Gross margin: Decrease of $27.6 million, largely resulting from lower asphalt product margins, as previously discussed, and lower construction margins of $8.8 million driven by decreased workloads caused by unfavorable weather during the first half of the year and less available work in energy-producing states. Partially offsetting these decreases were higher aggregate margins of $8.0 million, primarily due to strong commercial and residential demand in certain regions.

Selling, general and administrative expense: Increase of $7.9 million, largely resulting from the absence in 2017 of an $11.1 million reduction to a MEPP withdrawal liability. Partially offsetting the increase were lower depreciation, depletion and amortization expense and lower office expense.

Other income: Comparable to the prior year.

Interest expense: Comparable to the prior year.

Income taxes: Decrease of $55.2 million, largely resulting from an income tax benefit of $41.9 million for the revaluation of the segment's net deferred tax liabilities, as discussed in Item 8 - Note 13, and lower income before income taxes.

Outlook The segment's vertically integrated aggregates based business model provides the Company with the ability to capture margin throughout the sales delivery process. The aggregate products are sold internally and externally for use in other products such as ready-mixed concrete, asphaltic concrete and public and private construction markets. The contracting services and construction materials are sold primarily to construction contractors in connection with street, highway and other public infrastructure projects, as well as private commercial and residential development projects. The public infrastructure projects have traditionally been more stable markets as public funding is more secure during periods of economic decline. The public funding is, however, dependent on federal funding such as appropriations to the Federal Highway Administration. Spending on private development is highly dependent on both local and national economic cycles, providing additional sales during times of strong economic cycles.

The Company remains optimistic about overall economic growth and infrastructure spending. The IBISWorld Incorporated Industry Report issued in May 2018 for sand and gravel mining in the United States projects a 1.8 percent annual growth rate over the next five years. The report also states the demand for clay and refractory materials is projected to continue deteriorating in several downstream manufacturing industries, but this decline will be offset by stronger demand from the housing market and buoyant demand from the highway and bridge construction market. The Company believes stronger demand in the housing markets along with continued demand from the highway and bridge construction markets should provide a stable demand for construction materials and contracting products and services in the near future.

In April 2018, the Company acquired Teevin & Fischer Quarry, LLC, a crushed rock and gravel supplier in northwestern Oregon. In June 2018, the Company acquired Tri-City Paving, Inc., a general contractor and aggregate, asphalt and ready-mixed concrete supplier headquartered in Little Falls, Minnesota. In July 2018, the Company acquired Molalla Redi-Mix and Rock Products, Inc., which produces ready-mixed concrete in Molalla, Oregon. In October 2018, the Company acquired Sweetman Construction Company, a premier provider of aggregates, asphalt and ready-mixed concrete in Sioux Falls, South Dakota. These acquisitions are expected to be accretive to the segment's earnings in 2019. The Company continues to evaluate additional acquisition opportunities. For more information on these acquisitions, see Item 8 - Note 3.

The Company had backlog at December 31, 2018, of $706 million, up from $486 million at December 31, 2017. The Company has benefited from increased bidding opportunities in each of its regions. The increase in backlog was primarily attributable to work for state transportation departments, airports, the military, homebuilders and commercial developers. The Company expects to complete a significant amount of the backlog at December 31, 2018, during the next 12 months.

Construction Services

Strategy and challenges The construction services segment provides inside and outside specialty contracting, as discussed in Items 1 and 2 - Business Properties. The construction services segment focuses on providing a superior return on investment by building new and strengthening existing customer relationships; ensuring quality service; safely executing projects; effectively controlling costs; collecting on receivables; retaining, developing and recruiting talented employees; growing through organic and acquisition opportunities; and focusing efforts on projects that will permit higher margins while properly managing risk.

The construction services segment faces challenges in the highly competitive markets in which it operates. Competitive pricing environments, project delays and effects from restrictive regulatory requirements have negatively impacted margins in the past and could affect margins in the future. Additionally, margins may be negatively impacted on a quarterly basis due to adverse weather conditions, as well as timing of project starts or completions, declines or delays in new projects due to the cyclical nature of the construction industry and other factors. These challenges may also impact the risk of loss on certain projects. Accordingly, operating results in any particular period may not be indicative of the results that can be expected for any other period.

The need to ensure available specialized labor resources for projects also drives strategic relationships with customers and project margins. These trends include an aging workforce and labor availability issues, increasing pressure to reduce costs and improve reliability, and increasing duration and complexity of customer capital programs. Due to these and other factors, the Company believes customer demand for labor resources will continue to increase, possibly surpassing the supply of industry resources.

Earnings overview - The following information summarizes the performance of the construction services segment.

Years ended December 31,	2018	2017	2016
		(In millions)	
Operating revenues	$ 1,371.5	$ 1,367.6	$ 1,073.3
Cost of sales:			
Operation and maintenance	1,150.4	1,153.9	905.4
Depreciation, depletion and amortization	14.3	14.2	13.5
Taxes, other than income	42.0	43.4	35.2
Total cost of sales	1,206.7	1,211.5	954.1
Gross margin	164.8	156.1	119.2
Selling, general and administrative expense:			
Operation and maintenance	72.2	69.3	60.1
Depreciation, depletion and amortization	1.4	1.5	1.8
Taxes, other than income	4.4	4.0	3.8
Total selling, general and administrative expense	78.0	74.8	65.7
Operating income	86.8	81.3	53.5
Other income	1.1	1.3	2.2
Interest expense	3.6	3.7	4.0
Income before income taxes	84.3	78.9	51.7
Income taxes	20.0	25.6	17.8
Earnings	$ 64.3	$ 53.3	$ 33.9

2018 compared to 2017 Construction services earnings increased $11.0 million (21 percent) as a result of:

Revenues: Comparable to the prior year.

Gross margin: Increase of $8.7 million, largely resulting from higher outside specialty contracting gross margins due to increased outside equipment sales and rentals. Partially offsetting the increase were decreased inside specialty contracting gross margins as a result of decreased workloads and customer demand.

Selling, general and administrative expense: Increase of $3.2 million, primarily higher office expense, outside professional costs and payroll-related costs.

Other income: Comparable to the prior year.

Interest expense: Comparable to the prior year.

Income taxes: Decrease of $5.6 million, largely the lower corporate tax rate due to the enactment of the TCJA.

2017 compared to 2016 Construction services earnings increased $19.4 million (57 percent) as a result of:

Revenues: Increase of $294.3 million, primarily from an increase in the number and size of construction projects in 2017, as well as increased equipment sales and rentals.

Gross margin: Increase of $36.9 million resulting from higher inside specialty contracting margins of $20.9 million driven by increased revenues, as previously discussed, and decreased costs from the successful management of labor performance on projects in a majority of the business activities performed partially offset by job losses on certain projects. Also contributing to the increased margins were higher outside specialty contracting margins of $16.0 million driven by higher contracting workloads and equipment revenues in areas impacted by storm activity.

Selling, general and administrative expense: Increase of $9.1 million, primarily higher payroll-related costs, office expense and outside professional costs.

Other income: Decrease of $900,000 due to the absence of interest income earned on prior year completed jobs.

Interest expense: Comparable to the prior year.

Income taxes: Increase of $7.8 million resulting from an increase in income before income taxes and the absence in 2017 of a $1.5€million tax benefit related to the disposition of a non-strategic asset. Partially offsetting this increase was an income tax benefit of $4.3€million for the revaluation of the segment's net deferred tax liabilities, as discussed in Item 8 - Note 13.

Outlook The Company continues to expect long-term growth in the electric transmission and distribution market, although the timing of large bids and subsequent construction is likely to be highly variable from year to year. The Company believes several small and medium-sized transmission and distribution projects will continue to be available for bid in 2019. The Company expects bidding activity to remain strong for both outside and inside specialty construction companies in 2019. Although bidding remains highly competitive in all areas, the Company expects the segment's skilled workforce will continue to provide a benefit in securing and executing profitable projects.

The Company had backlog at December€31, 2018, of $939 million, up from $708 million at December€31, 2017. The increase in backlog was largely attributable to the new project opportunities that the Company continues to see across its diverse operations, particularly in inside specialty electrical and mechanical contracting for the hospitality and gaming, high-tech, mission critical and public entities. The Company's outside power, communications and natural gas specialty operations also have a high volume of work. The Company expects to complete a significant amount of the backlog at December€31, 2018, during the next 12 months. Additionally, the Company continues to evaluate potential acquisition opportunities that would be accretive to the Company and grow the Company's backlog.

Other

Years ended December 31,	2018	2017	2016
		(In millions)	
Operating revenues	$ 11.3	$ 7.9	$ 8.6
Operating expenses:			
Operation and maintenance	9.3	6.3	6.7
Depreciation, depletion and amortization	2.0	2.0	2.1
Taxes, other than income	.1	.2	.1
Total operating expenses	11.4	8.5	8.9
Operating loss	(.1)	(.6)	(.3)
Other income	1.0	.9	.9
Interest expense	2.8	3.6	5.8
Loss before income taxes	(1.9)	(3.3)	(5.2)
Income taxes	(1.2)	(1.8)	(2.0)
Loss	$ (.7)	$ (1.5)	$ (3.2)

Included in Other are general and administrative costs and interest expense previously allocated to the exploration and production and refining businesses that do not meet the criteria for income (loss) from discontinued operations. Largely contributing to the increase in operation and maintenance expense in 2018 were costs associated with the Holding Company Reorganization. For further details on the Company's reorganization, see Items 1 and 2 Business Properties - General.

Discontinued Operations

Years ended December 31,	2018	2017	2016
		(In millions)	
Income (loss) from discontinued operations before intercompany eliminations, net of tax	$ 2.9	$ 3.1	$ (303.2)
Intercompany eliminations	•	(6.9)	2.8
Income (loss) from discontinued operations, net of tax	2.9	(3.8)	(300.4)
Loss from discontinued operations attributable to noncontrolling interest	•	„	(131.7)
Income (loss) from discontinued operations attributable to the Company, net of tax	$ 2.9	$ (3.8)	$ (168.7)

2018 compared to 2017 The income from discontinued operations attributable to the Company was $2.9€million, primarily related to income tax adjustments, compared to a loss of $3.8€million in the prior year. The loss in 2017 was largely due to eliminations for the presentation of income tax adjustments between continuing and discontinued operations.

2017 compared to 2016 The loss from discontinued operations attributable to the Company was $3.8€million compared to a loss of $168.7€million in the prior year. The decreased loss was largely due to the absence in 2017 of a loss associated with the sale of the refining business in June 2016, as well as the reversal in 2017 of a previously accrued liability due to the resolution of a legal matter, as discussed in Item 8 - Note 4.

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 related to these items were as follows:

Years ended December 31,	2018	2017	2016
	(In millions)		
Intersegment transactions:			
Operating revenues	$ 64.3	$ 58.0	$ 57.4
Operation and maintenance	13.7	9.1	8.7
Purchased natural gas sold	50.6	48.9	48.7
Income from continuing operations*	•	(6.9)	(6.3)

* Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.

For more information on intersegment eliminations, see Item 8 - Note 15.

Liquidity and Capital Commitments

At December 31, 2018, the Company had cash and cash equivalents of $53.9 million and available borrowing capacity of $384.6 million under the outstanding credit facilities of the Company and its subsidiaries. The Company expects to meet its obligations for debt maturing within one year and its other operating and capital requirements from various sources, including internally generated funds; the Company's credit facilities, as described later in Capital resources; the issuance of long-term debt; and issuance of equity securities.

Cash flows

Operating activities The changes in cash flows from operating activities generally follow the results of operations as discussed in Business Segment Financial and Operating Data and also are affected by changes in working capital. Changes in cash flows for discontinued operations are related to the former exploration and production and refining businesses. Cash flows provided by operating activities in 2018 increased $51.9 million from 2017.

Increases: The increase in cash flows provided by operating activities was largely driven by stronger collection of accounts receivable at the construction services and construction materials and contracting businesses and bonus depreciation for tax purposes due to the enactment of TCJA at the construction materials and contracting business.

Decreases: Partially offsetting these increases were higher inventory balances at the construction materials and contracting business due to higher asphalt oil inventory, largely resulting from higher average per ton cost, and higher aggregate inventory from higher production. Also contributing to the decrease were decreased deferral of production tax credits, re-measurements of taxes on investments and accelerated tax deductions related to the TCJA.

Cash flows provided by operating activities in 2017 decreased $14.2 million from 2016. The decrease in cash flows provided by operating activities reflects higher working capital requirements at the construction services business largely resulting from higher receivables due to increased workloads during the year and at the construction materials business due to higher receivables resulting from increased workloads later in the year. Higher natural gas purchases including the effects of colder weather also added to higher working capital requirements at the natural gas distribution business. Higher income taxes paid from continuing operations was largely offset by higher income tax benefits received from discontinued operations resulting from the realization of net operating losses at the discontinued operations. Higher earnings from continuing operations in 2017, compared to 2016, partially offset the decrease in cash flows provided by operating activities. Higher margins at the electric, natural gas distribution and construction services businesses were partially offset by lower margins at the construction materials business.

Investing activities Cash flows used in investing activities in 2018 increased $496.7 million from 2017. The increase in cash used in investing activities was primarily related to acquisition activity in 2018 at the construction materials and contracting business; the absence in 2018 of net proceeds from the sale of Pronghorn in January 2017 and higher capital expenditures in 2018 at the pipeline and midstream business; and higher capital expenditures related to various construction projects in 2018 at the electric and natural gas distribution businesses.

Cash flows used in investing activities in 2017 decreased $90.9 million from 2016, largely resulting from net proceeds from the sale of Pronghorn in January 2017 at the pipeline and midstream business.

Financing activities Cash flows provided by financing activities in 2018 increased $475.7 million from 2017. The increase in cash provided by financing activities was largely due to increased debt issuance from an increase in commercial paper balances used for acquisitions, ongoing capital expenditures and working capital needs at the construction materials and contacting business; the issuance of an additional $200 million in term loans for capital projects at the electric and natural gas distribution businesses; and the issuance of an additional $40 million under the private shelf agreement for capital projects at the pipeline and midstream business. The increase in issuance of long-term debt was partially offset by higher debt repayment on a line of credit at the natural gas distribution business; higher debt repayment on debt that matured during third quarter 2018 at the electric and natural gas distribution businesses; and the strong collection of accounts receivable resulting in lower commercial paper balances at the construction services business.

Cash flows used in financing activities in 2017 increased $50.4 million from 2016, primarily due to the higher net repayment of long-term debt.

Defined benefit pension plans

The Company has noncontributory qualified 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 and expected return on plan assets. At December 31, 2018, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $83.8 million. Pretax pension expense reflected in the Company's Consolidated Statements of Income for the years ended December 31, 2018, 2017 and 2016, was $843,000, $1.7 million and $2.0 million, respectively. The Company's pension expense is currently projected to be less than $1.0 million in 2019. Funding for the pension plans is actuarially determined. The minimum required contributions for the year ended December 31, 2018 were approximately $6.1 million. There were no minimum required contributions for 2017 and 2016. For more information on the Company's pension plans, see Item 8 - Note 16.

Capital expenditures

The Company's capital expenditures from continuing operations for 2016 through 2018 and as anticipated for 2019 through 2021 are summarized in the following table.

	Actual*			Estimated		
	2016	2017	2018	2019	2020	2021
			(In millions)			
Capital expenditures:						
Electric	$ 111	$ 109	$ 186	$ 104	$ 103	$ 88
Natural gas distribution	126	147	206	204	180	158
Pipeline and midstream	35	31	70	113	93	204
Construction materials and contracting	38	44	280	133	135	127
Construction services	60	19	25	25	17	18
Other	2	2	2	5	3	3
Total capital expenditures	$ 372	$ 352	$ 769	$ 584	$ 531	$ 598

* Capital expenditures for 2018, 2017 and 2016 include noncash transactions such as the issuance of the Company's equity securities in connection with acquisitions, capital expenditure-related accounts payable and AFUDC, totaling $33.4 million, $10.5 million and $(15.8) million, respectively.

The 2018 capital expenditures include the four acquisitions at the construction materials and contracting segment, as discussed in Item 8 - Note 3. The 2018 capital expenditures were funded by internal sources, issuance of long-term debt and issuance of the Company's equity securities. The Company has included in the estimated capital expenditures for 2019 through 2021 the Demicks Lake project, Line Section 22 Expansion project and North Bakken Expansion project, as previously discussed in Business Segment Financial and Operating Data

Estimated capital expenditures for the years 2019 through 2021 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
- Power generation and transmission opportunities
- Environmental upgrades
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities that would be incremental to the outlined capital program; 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 for the years 2019 through 2021 will be funded by various sources, including internally generated funds; the Company's credit facilities, as described later; issuance of long-term debt; and issuance of equity securities.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive and financial 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, 2018. 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 more information on the covenants, certain other conditions and cross-default provisions, see Item 8 - Note 8.

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at December 31, 2018:

Company	Facility		Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date
					(In millions)				
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$ 175.0		$ 48.5		$ —		6/8/23
Cascade Natural Gas Corporation	Revolving credit agreement		$ 75.0	(c)	$ 53.8		$ 2.2	(d)	4/24/20
Intermountain Gas Company	Revolving credit agreement		$ 85.0	(e)	$ 56.3		$ —		4/24/20
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$ 500.0		$ 289.6	(b)	$ —		9/23/21

(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 $225.0 million). The amount outstanding under the revolving credit agreement was $48.5 million.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $100.0 million.
(d) Outstanding letter(s) of credit reduce the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $110.0 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 $600.0 million). There were no amounts outstanding under the revolving 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.

Total equity as a percent of total capitalization was 55 percent and 59 percent at December 31, 2018 and 2017, respectively. 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 is an indicator of how the Company is financing its operations, as well as its financial strength.

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. Historically, 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 in the future, 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.

On January 1, 2019, the Company's revolving credit agreement and commercial paper program became Montana-Dakota's revolving credit agreement and commercial paper program as a result of the Holding Company Reorganization. The outstanding balance of the revolving credit agreement was also transferred to Montana-Dakota. All of the related terms and covenants of the credit agreements remained the same.

Prior to the maturity of the credit agreement, Montana-Dakota expects that it will negotiate the extension or replacement of this agreement. If Montana-Dakota 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 Montana-Dakota does not currently anticipate, it would seek alternative funding.

Cascade Cascade's credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's ratio of total debt to total capitalization as of December 31, 2018, was 51 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.

Intermountain Intermountain's 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. Intermountain's ratio of total debt to total capitalization as of December 31, 2018, was 49 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 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. Historically, 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 in the future, 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 WBI Energy Transmission has a $200.0 million uncommitted note purchase and private shelf agreement with an expiration date of May 16, 2019. WBI Energy Transmission had $140.0 million of notes outstanding at December 31, 2018, which reduced the remaining capacity under this uncommitted private shelf agreement to $60.0 million.

Off balance sheet arrangements

As of December 31, 2018, the Company had no material off balance sheet arrangements as defined by the rules of the SEC.

Contractual obligations and commercial commitments

For more information on the Company's contractual obligations on long-term debt, operating leases and purchase commitments, see Item 8 - Notes 8 and 19. At December 31, 2018, the Company's commitments under these obligations were as follows:

	Less than 1 year	1-3 years	3-5 years	More than 5 years	Total
	(In millions)				
Long-term debt*	$ 251.9	$ 416.3	$ 273.0	$ 1,173.0	$ 2,114.2
Estimated interest payments**	83.0	153.9	123.6	472.5	833.0
Operating leases	37.7	44.2	18.9	49.1	149.9
Purchase commitments	418.1	384.8	200.1	622.4	1,625.4
	$ 790.7	$ 999.2	$ 615.6	$ 2,317.0	$ 4,722.5

* Unamortized debt issuance costs and discount are excluded from the table.
** Estimated interest payments are calculated based on the applicable rates and payment dates.

At December 31, 2018, the Company had total liabilities of $375.6 million related to asset retirement obligations that are excluded from the table above. Of the total asset retirement obligations, the current portion was $5.0 million at December 31, 2018, 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 deferred credits and other liabilities - other 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 9.

Not reflected in the previous table are $382,000 in uncertain tax positions at December 31, 2018. For more information, see Item 8 - Note 13.

The Company's minimum funding requirements for its defined benefit pension plans for 2019, which are not reflected in the previous table, are $4.0 million. For information on potential contributions above the funding minimum requirements, see item 8 - Note 16.

The Company's MEPP 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 MEPPs as a result of their funded status. For more information, see Item 1A - Risk Factors and Item 8 - Note 16.

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 and goodwill; fair values of acquired assets and liabilities under the acquisition method of accounting; aggregate reserves; property depreciable lives; tax provisions; revenue recognized using the cost-to-cost measure of progress for contracts; 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; and the valuation of stock-based compensation. 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.

Impairment of long-lived assets and intangibles

The Company reviews the carrying values of its long-lived assets and intangibles, excluding assets held for sale, 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, 2018, 2017 and 2016, there were no impairment losses recorded. At December 31, 2018, 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, risk adjusted 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 risk adjusted cost of capital at each reporting unit. The risk adjusted cost of capital, which varies by reporting unit and is in the range of 5 percent to 9 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 2018. Under the market approach, the Company estimates fair value using multiples derived from 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.

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.

Business combinations

The Company accounts for acquisitions on the Consolidated Financial Statements starting from the date of the acquisition, which is the date that control is obtained. The acquisition method of accounting requires acquired assets and liabilities assumed be recorded at their respective fair values as of the date of the acquisition. The excess of the purchase price over the fair value of the assets acquired and liabilities assumed is recorded as goodwill. The estimation of fair values of acquired assets and liabilities assumed by the Company requires significant judgment and requires various assumptions. Although independent appraisals may be used to assist in the determination of the fair value of certain assets and liabilities, the appraised values may be based on significant estimates provided by management. The amounts and useful lives assigned to depreciable and amortizable assets compared to amounts assigned to goodwill, which is not amortized, can affect the results of operations in the period of and periods subsequent to a business combination.

In determining fair values of acquired assets and liabilities assumed, the Company uses various observable inputs for similar assets or liabilities in active markets and various unobservable inputs, which includes the use of valuation models. Fair values are based on various factors including, but not limited to, age and condition of property, maintenance records, auction values for equipment with similar characteristics, recent sales and listings of comparable properties, data collected from drill holes and other subsurface investigations and geologic data. The Company primarily uses the market and cost approaches in determining the fair value of land and property, plant and equipment. A combination of the market and income approaches are used for aggregate reserves and intangibles, primarily a discounted cash flow model.

There is a measurement period after the acquisition date during which the Company may adjust the amounts recognized for a business combination. Any such adjustments are recorded in the period the adjustment is determined with the corresponding offset to goodwill. These adjustments are typically based on obtaining additional information that existed at the acquisition date regarding the assets acquired and the liabilities assumed. The measurement period ends once the Company has obtained all necessary information that existed as of the acquisition date, but does not extend beyond one year from the date of the acquisition. Once the measurement period has ended, any adjustments to assets acquired or liabilities assumed are recorded in income from continuing operations.

Revenue recognition

Revenue is recognized to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The recognition of revenue requires the Company to make estimates and assumptions that affect the reported amounts of revenue. The accuracy of revenues reported on the Consolidated Financial Statements depends on, among other things, management's estimates of total costs to complete projects because the Company uses the cost-to-cost measure of progress on construction contracts for revenue recognition.

To determine the proper revenue recognition method for contracts, the Company evaluates whether two or more contracts should be combined and accounted for as one single contract and whether the combined or single contract should be accounted for as more than one performance obligation. This evaluation requires significant judgment and the decision to combine a group of contracts or separate the combined or single contract into multiple performance obligations could change the amount of revenue and profit recorded in a given period. For most contracts, the customer contracts with the Company to provide a significant service of integrating a complex set of tasks and components into a single project. Hence, the Company's contracts are generally accounted for as one performance obligation.

The Company recognizes construction contract revenue over time using the cost-to-cost measure of progress for contracts because it best depicts the transfer of assets to the customer which occurs as the Company incurs costs on the contract. Under the cost-to-cost measure of progress, the costs incurred are compared with total estimated costs of a performance obligation. Revenues are recorded proportionately to the costs incurred. 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.

Contracts are often modified to account for changes in contract specifications and requirements. The Company considers contract modifications to exist when the modification either creates new or changes the existing enforceable rights and obligations. Generally, contract modifications are for goods or services that are not distinct from the existing contract due to the significant integration of services provided in the context of the contract and are accounted for as if they were part of that existing contract. The effect of a contract modification on the transaction price and the measure of progress for the performance obligation to which it relates, is recognized as an adjustment to revenue on a cumulative catch-up basis.

The Company's construction contracts generally contain variable consideration including liquidated damages, performance bonuses or incentives, claims, unapproved/unpriced change orders and penalties or index pricing. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using estimation methods that best predict the most likely amount of consideration the Company expects to be entitled to or expects to incur. The Company includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis.

The Company believes its estimates surrounding the cost-to-cost method 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.

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, actuarially determined mortality data and health care 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 health care 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, 2018.

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 health care cost trend rates. The Company plans to continue to use its current methodologies to determine plan costs. For more information on the assumptions used in determining plan costs, see Item 8 - Note 16.

Income taxes

The Company is required to make judgments regarding the potential tax effects of various financial transactions and ongoing operations to estimate the Company's obligation to taxing authorities. These tax obligations include income, real estate, franchise and sales/use taxes. Judgments related to income taxes require the recognition in the Company's financial statements a tax position that is more-likely-than-not to be sustained on audit.

Judgment and estimation is required in developing the provision for income taxes and the reporting of tax-related assets and liabilities and, if necessary, any valuation allowances. The interpretation of tax laws can involve uncertainty, since tax authorities may interpret such laws differently. Actual income tax could vary from estimated amounts and may result in favorable or unfavorable impacts to net income, cash flows, and tax-related assets and liabilities. In addition, the effective tax rate may be affected by other changes including the allocation of property, payroll and revenues between states.

The Company assesses the deferred tax assets for recoverability taking into consideration historical and anticipated earnings levels; the reversal of other existing temporary differences; available net operating losses and tax carryforwards; and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, a valuation allowance against the deferred tax assets. As facts and circumstances change, adjustment to the valuation allowance may be required.

Non-GAAP Financial Measures

The Business Segment Financial and Operating Data includes financial information prepared in accordance with GAAP, as well as another financial measure, adjusted gross margin, that is considered a non-GAAP financial measure as it relates to the Company's electric and natural gas distribution segments. The presentation of adjusted gross margin is intended to be a useful supplemental financial measure for investorsƒ understanding of the segments' operating performance. This non-GAAP financial measure should not be considered as an alternative to, or more meaningful than, GAAP financial measures such as operating income (loss) or earnings (loss). The Company's non-GAAP financial measure, adjusted gross margin, is not standardized; therefore, it may not be possible to compare this financial measure with other companiesƒ gross margin measures having the same or similar names.

In addition to operating revenues and operating expenses, management also uses the non-GAAP financial measure of adjusted gross margin when evaluating the results of operations for the electric and natural gas distribution segments. Adjusted gross margin for the electric and natural gas distribution segments is calculated by adding back adjustments to operating income (loss). These add-back adjustments include: operation and maintenance expense; depreciation, depletion and amortization expense; and certain taxes, other than income.

Adjusted gross margin includes operating revenues less the cost of electric fuel and purchased power, purchased natural gas sold and certain taxes, other than income. These taxes, other than income, included as a reduction to adjusted gross margin relate to revenue taxes. These segments pass on to their customers the increases and decreases in the wholesale cost of power purchases, natural gas and other fuel supply costs in accordance with regulatory requirements. As such, the segments' revenues are directly impacted by the fluctuations in such commodities. Revenue taxes, which are passed back to customers, fluctuate with revenues as they are calculated as a percentage of revenues. For these reasons, period over period, the segments' operating income (loss) is generally not impacted. The Company's management believes the adjusted gross margin is a useful supplemental financial measure as these items are included in both operating revenues and operating expenses. The Company's management also believes that adjusted gross margin and the remaining operating expenses that calculate operating income (loss) are useful in assessing the Company's utility performance as management has the ability to influence control over the remaining operating expenses.

The following information reconciles operating income to adjusted gross margin for the electric segment.

Years ended December 31,	2018	2017	2016
		(In€millions)	
Operating income	$ 65.2	$ 79.9	$ 67.9
Adjustments:			
Operating expenses:			
Operation and maintenance	123.0	122.2	115.8
Depreciation, depletion and amortization	51.0	47.7	50.2
Taxes, other than income	14.5	13.5	12.3
Total adjustments	188.5	183.4	178.3
Adjusted gross margin	$ 253.7	$ 263.3	$ 246.2

The following information reconciles operating income to adjusted gross margin for the natural gas distribution segment.

Years ended December 31,	2018	2017	2016
		(In millions)	
Operating income	$ 72.3	$ 84.3	$ 66.2
Adjustments:			
Operating expenses:			
Operation and maintenance	173.4	164.3	156.9
Depreciation, depletion and amortization	72.5	69.4	65.4
Taxes, other than income	21.7	20.5	19.6
Total adjustments	267.6	254.2	241.9
Adjusted gross margin	$ 339.9	$ 338.5	$ 308.1

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2018 , 2017 or 2016 .

Item€7A. Quantitative and Qualitative Disclosures About Market Risk

The Company is exposed to the impact of market fluctuations associated with interest rates. The Company has policies and procedures to assist in controlling these market risks and from time to time has utilized derivatives to manage a portion of its risk.

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 has utilized 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. For additional information on the Company's long-term debt, see Item 8 - Notes 7 and 8.

At December€31, 2018 and 2017, the Company had no outstanding interest rate hedges.

The following table shows the amount of long-term debt, which excludes unamortized debt issuance costs and discount, and related weighted average interest rates, both by expected maturity dates, as of December€31, 2018.

	2019	2020	2021	2022	2023	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$ 51.9	$ 15.8	$ .8	$ 147.3	$ 77.2	$ 1,173.0	$ 1,466.0	$ 1,540.9
Weighted average interest rate	4.3%	5.1%	2.2%	4.5%	3.7%	4.7%	4.6%	„
Variable rate	$ 200.0	$ 110.1	$ 289.6	„	$ 48.5	„	$ 648.2	$ 648.2
Weighted average interest rate	2.8%	4.4%	3.1%	„	2.8%	„	3.2%	„

Item 8. Financial Statements and Supplementary Data

Management's Report on Internal Control Over Financial Reporting

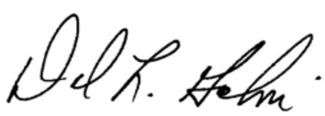
The management of MDU Resources Group, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Company's internal control system is designed to provide reasonable 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, 2018. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework (2013).

Based on our evaluation under the framework in Internal Control-Integrated Framework (2013), management concluded that the Company's internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2018, 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

Jason L. Vollmer
Vice President, Chief Financial Officer and Treasurer

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of MDU Resources Group, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December€31, 2018 and 2017, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December€31, 2018, and the related notes and the financial statement schedules listed in the Index at Item€15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December€31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December€31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December€31, 2018, based on criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February€22, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Deloitte & Touche LLP

Minneapolis, Minnesota
February 22, 2019

We have served as the Company's auditor since 2002.

Report of Independent Registered Public Accounting Firm

To the Stockholders and the Board of Directors of MDU Resources Group, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of MDU Resources Group,€Inc. and subsidiaries (the "Company") as of December€31, 2018, based on criteria established in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December€31, 2018, based on criteria established in Internal Control-Integrated Framework (2013) issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedules as of and for the year ended December€31, 2018, of the Company and our report dated February€22, 2019, expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

Basis for Opinion

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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and Limitations of Internal Control over Financial Reporting

A companyƒs internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A companyƒs 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 companyƒs assets that could have a material effect on the financial statements.

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

Deloitte & Touche LLP

Minneapolis, Minnesota
February 22, 2019

Consolidated Statements of Income

Years ended December€31,	2018	2017	2016
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and regulated pipeline and midstream	$ 1,213,227	$ 1,244,759	$ 1,141,454
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other	3,318,325	3,198,592	2,987,374
Total operating revenues	4,531,552	4,443,351	4,128,828
Operating expenses:			
Operation and maintenance:			
Electric, natural gas distribution and regulated pipeline and midstream	340,331	326,687	312,211
Nonregulated pipeline and midstream,€construction materials and contracting, construction services and other	2,915,790	2,808,779	2,581,299
Total operation and maintenance	3,256,121	3,135,466	2,893,510
Purchased natural gas sold	404,153	430,954	382,753
Depreciation, depletion and amortization	220,205	207,486	216,318
Taxes, other than income	168,638	166,673	151,826
Electric fuel and purchased power	80,712	78,724	75,512
Total operating expenses	4,129,829	4,019,303	3,719,919
Operating income	401,723	424,048	408,909
Other income (expense)	(238)	8,767	5,167
Interest expense	84,614	82,788	87,848
Income before income taxes	316,871	350,027	326,228
Income taxes	47,485	65,041	93,132
Income from continuing operations	269,386	284,986	233,096
Income (loss) from discontinued operations, net of tax (Note 4)	2,932	(3,783)	(300,354)
Net income (loss)	272,318	281,203	(67,258)
Loss from discontinued operations attributable to noncontrolling interest (Note 4)	•	„	(131,691)
Loss on redemption of preferred stocks (Note 10)	•	600	„
Dividends declared on preferred stocks	•	171	685
Earnings on common stock	$ 272,318	$ 280,432	$ 63,748
Earnings per common share - basic:			
Earnings before discontinued operations	$ 1.38	$ 1.46	$ 1.19
Discontinued operations attributable to the Company, net of tax	.01	(.02)	(.86)
Earnings per common share - basic	$ 1.39	$ 1.44	$ .33
Earnings per common share - diluted:			
Earnings before discontinued operations	$ 1.38	$ 1.45	$ 1.19
Discontinued operations attributable to the Company, net of tax	.01	(.02)	(.86)
Earnings per common share - diluted	$ 1.39	$ 1.43	$ .33
Weighted average common shares outstanding - basic	195,720	195,304	195,299
Weighted average common shares outstanding - diluted	196,150	195,687	195,618

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

Consolidated Statements of Comprehensive Income

Years ended December€31,	2018	2017	2016
		(In thousands)	
Net income (loss)	$ 272,318	$ 281,203	$ (67,258)
Other comprehensive income (loss):			
Reclassification adjustment for loss on derivative instruments included in net income (loss), net of tax of $429, $224 and $226 in 2018, 2017 and 2016, respectively	162	366	367
Postretirement liability adjustment:			
Postretirement liability gains (losses) arising during the period, net of tax of $1,471, $(1,162) and $(836) in 2018, 2017 and 2016, respectively	4,441	(1,812)	(1,470)
Amortization of postretirement liability losses included in net periodic benefit cost (credit), net of tax of $721, $645 and $1,425 in 2018, 2017 and 2016, respectively	2,173	1,013	2,506
Reclassification of postretirement liability adjustment from regulatory asset, net of tax of $0, $(876) and $0 in 2018, 2017 and 2016, respectively	•	(1,143)	„
Postretirement liability adjustment	6,614	(1,942)	1,036
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of $(14), $(3) and $31 in 2018, 2017 and 2016, respectively	(61)	(6)	51
Reclassification adjustment for foreign currency translation adjustment included in net income (loss), net of tax of $75, $0 and $0 in 2018, 2017 and 2016, respectively	249	„	„
Foreign currency translation adjustment	188	(6)	51
Net unrealized loss on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(38), $(75) and $(98) in 2018, 2017 and 2016, respectively	(144)	(139)	(182)
Reclassification adjustment for loss on available-for-sale investments included in net income (loss), net of tax of $35, $65 and $77 in 2018, 2017 and 2016, respectively	131	120	143
Net unrealized loss on available-for-sale investments	(13)	(19)	(39)
Other comprehensive income (loss)	6,951	(1,601)	1,415
Comprehensive income (loss)	279,269	279,602	(65,843)
Comprehensive loss from discontinued operations attributable to noncontrolling interest	•	„	(131,691)
Comprehensive income attributable to common stockholders	$ 279,269	$ 279,602	$ 65,848

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

Consolidated Balance Sheets

December 31,	2018	2017
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 53,948	$ 34,599
Receivables, net	722,945	727,030
Inventories	287,309	226,583
Prepayments and other current assets	119,500	81,304
Current assets held for sale	430	479
Total current assets	1,184,132	1,069,995
Investments	138,620	137,613
Property, plant and equipment (Note 1)	7,397,321	6,770,829
Less accumulated depreciation, depletion and amortization	2,818,644	2,691,641
Net property, plant and equipment	4,578,677	4,079,188
Deferred charges and other assets:		
Goodwill (Note 5)	664,922	631,791
Other intangible assets, net (Note 5)	10,815	3,837
Other	408,857	407,850
Noncurrent assets held for sale	2,087	4,392
Total deferred charges and other assets	1,086,681	1,047,870
Total assets	$ 6,988,110	$ 6,334,666
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	$ 251,854	$ 148,499
Accounts payable	358,505	312,327
Taxes payable	41,929	42,537
Dividends payable	39,695	38,573
Accrued compensation	69,007	72,919
Other accrued liabilities	221,059	186,010
Current liabilities held for sale	4,001	11,993
Total current liabilities	986,050	812,858
Long-term debt (Note 8)	1,856,841	1,566,354
Deferred credits and other liabilities:		
Deferred income taxes	430,085	347,271
Other	1,148,359	1,179,140
Total deferred credits and other liabilities	1,578,444	1,526,411
Commitments and contingencies (Notes 16, 18 and 19)		
Stockholders' equity:		
Common stock (Note 11)		
Authorized - 500,000,000 shares, $1.00 par value Issued - 196,564,907 shares in 2018 and 195,843,297 shares in 2017	196,565	195,843
Other paid-in capital	1,248,576	1,233,412
Retained earnings	1,163,602	1,040,748
Accumulated other comprehensive loss	(38,342)	(37,334)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total stockholders' equity	2,566,775	2,429,043
Total liabilities and stockholders' equity	$ 6,988,110	$ 6,334,666

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

Consolidated Statements of Equity

Years ended December€31, 2018, 2017 and 2016

	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)										
At December€31, 2015	150,000	$15,000	195,804,665	$195,805	$1,230,119	$ 996,355	$(37,148)	(538,921)	$(3,626)	$124,043	$2,520,548
Net income (loss)	„	„	„	„	„	64,433	„	„	„	(131,691)	(67,258)
Other comprehensive income	„	„	„	„	„	„	1,415	„	„	„	1,415
Dividends declared on preferred stocks	„	„	„	„	„	(685)	„	„	„	„	(685)
Dividends declared on common stock	„	„	„	„	„	(147,821)	„	„	„	„	(147,821)
Stock-based compensation	„	„	„	„	4,383	„	„	„	„	„	4,383
Net tax deficit on stock-based compensation	„	„	„	„	(1,663)	„	„	„	„	„	(1,663)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	„	„	38,632	38	(361)	„	„	„	„	„	(323)
Contribution from noncontrolling interest	„	„	„	„	„	„	„	„	„	7,648	7,648
At December€31, 2016	150,000	15,000	195,843,297	195,843	1,232,478	912,282	(35,733)	(538,921)	(3,626)	„	2,316,244
Net income	„	„	„	„	„	281,203	„	„	„	„	281,203
Other comprehensive loss	„	„	„	„	„	„	(1,601)	„	„	„	(1,601)
Dividends declared on preferred stocks	„	„	„	„	„	(171)	„	„	„	„	(171)
Dividends declared on common stock	„	„	„	„	„	(151,966)	„	„	„	„	(151,966)
Stock-based compensation	„	„	„	„	3,375	„	„	„	„	„	3,375
Repurchase of common stock	„	„	„	„	„	„	„	(64,384)	(1,684)		(1,684)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	„	„	„	„	(2,441)	„	„	64,384	1,684	„	(757)
Redemption of preferred stock	(150,000)	(15,000)	„	„	„	(600)	„	„	„	„	(15,600)
At December€31, 2017	„	„	195,843,297	195,843	1,233,412	1,040,748	(37,334)	(538,921)	(3,626)	„	2,429,043
Cumulative effect of adoption of ASU 2014-09	„	„	„	„	„	(970)	„	„	„	„	(970)
Adjusted balance at January 1, 2018	„	„	195,843,297	195,843	1,233,412	1,039,778	(37,334)	(538,921)	(3,626)	„	2,428,073
Net income	„	„	„	„	„	272,318	„	„	„	„	272,318
Other comprehensive income	„	„	„	„	„	„	6,951	„	„	„	6,951
Reclassification of certain prior period tax effects from accumulated other comprehensive loss	„	„	„	„	„	7,959	(7,959)	„	„	„	„
Dividends declared on common stock	„	„	„	„	„	(156,453)	„	„	„	„	(156,453)
Stock-based compensation	„	„	„	„	5,060	„	„	„	„	„	5,060
Repurchase of common stock	„	„	„	„	„	„	„	(182,424)	(5,020)	„	(5,020)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	„	„	„	„	(7,350)	„	„	182,424	5,020	„	(2,330)
Issuance of common stock	„	„	721,610	722	17,454	„	„	„	„	„	18,176
At December€31, 2018	•	$ •	196,564,907	$ 196,565	$ 1,248,576	$ 1,163,602	$ (38,342)	(538,921)	$ (3,626)	$ •	$ 2,566,775

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

Consolidated Statements of Cash Flows

Years ended December€31,	2018	2017	2016
		(In thousands)	
Operating activities:			
Net income (loss)	$ 272,318	$ 281,203	$ (67,258)
Income (loss) from discontinued operations, net of tax	2,932	(3,783)	(300,354)
Income from continuing operations	269,386	284,986	233,096
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	220,205	207,486	216,318
Deferred income taxes	59,735	(25,423)	(2,049)
Changes in current assets and liabilities, net of acquisitions:			
Receivables	28,234	(108,255)	(25,641)
Inventories	(46,796)	9,135	2,433
Other current assets	(31,814)	(30,588)	(17,925)
Accounts payable	21,109	26,013	7,039
Other current liabilities	22,285	4,648	36,146
Other noncurrent changes	(38,521)	(18,790)	(26,459)
Net cash provided by continuing operations	503,823	349,212	422,958
Net cash provided by (used in) discontinued operations	(3,942)	98,799	39,251
Net cash provided by operating activities	499,881	448,011	462,209
Investing activities:			
Capital expenditures	(568,230)	(341,382)	(388,183)
Acquisitions, net of cash acquired	(167,692)	„	„
Net proceeds from sale or disposition of property and other	26,100	126,588	44,826
Investments	(2,321)	(1,608)	(1,396)
Net cash used in continuing operations	(712,143)	(216,402)	(344,753)
Net cash provided by discontinued operations	1,236	2,234	39,658
Net cash used in investing activities	(710,907)	(214,168)	(305,095)
Financing activities:			
Issuance of long-term debt	566,829	140,812	309,064
Repayment of long-term debt	(174,520)	(217,394)	(315,647)
Payments of stock issuance costs	(10)	„	„
Dividends paid	(154,573)	(150,727)	(147,156)
Redemption of preferred stock	•	(15,600)	„
Repurchase of common stock	(5,020)	(1,684)	„
Tax withholding on stock-based compensation	(2,330)	(757)	(323)
Net cash provided by (used in) continuing operations	230,376	(245,350)	(154,062)
Net cash used in discontinued operations	•	„	(40,852)
Net cash provided by (used in) financing activities	230,376	(245,350)	(194,914)
Effect of exchange rate changes on cash and cash equivalents	(1)	(1)	4
Increase (decrease) in cash and cash equivalents	19,349	(11,508)	(37,796)
Cash and cash equivalents - beginning of year	34,599	46,107	83,903
Cash and cash equivalents - end of year	$ 53,948	$ 34,599	$ 46,107

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 abbreviations and acronyms used throughout are defined following the Notes to Consolidated Financial Statements. The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline and midstream, construction materials and contracting, construction services and other. The electric and natural gas distribution businesses, as well as a portion of the pipeline and midstream business, are regulated. Construction materials and contracting, construction services and the other businesses, as well as a portion of the pipeline and midstream business, 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.

On January 2, 2019, the Company announced the completion of the Holding Company Reorganization, which resulted in Montana-Dakota and Great Plains becoming a subsidiary of the Company. The purpose of the reorganization was to make the public utility divisions into a subsidiary of the holding company, just as the other operating companies are wholly owned subsidiaries. Unless otherwise indicated, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's corporate structure prior to the Holding Company Reorganization.

On December 22, 2017, President Trump signed into law the TCJA which includes lower corporate tax rates, repealing the domestic production deduction, disallowance of immediate expensing for regulated utility property and modifying or repealing many other business deductions and credits. The reduction in the corporate tax rate was effective on January 1, 2018. The effects of the change in tax laws or rates must be accounted for in the period of enactment, which resulted in the Company making reasonable estimates of the impact of the reduction in corporate tax rate on the Company's net deferred tax liabilities during the fourth quarter of 2017. The SEC issued rules that allowed for a measurement period of up to one year after the enactment date of the TCJA to finalize the recording of the related tax impacts. At December 31, 2018, the Company finalized the estimates from the fourth quarter of 2017 and no material adjustments were recorded to income from continuing operations during the twelve months ended December 31, 2018.

Due to the enactment of the TCJA, the regulated jurisdictions in which the Company's regulated businesses provide service requested the Company furnish plans for the effect of the reduced corporate tax rate, which impacted the Company's rates to customers. Therefore, the Company reserved for such impacts as an offset to revenue or passed back to customers through lower rates in certain jurisdictions. For more information on the details and statuses of the open requests, see Note 18.

Effective January 1, 2018, the Company adopted the requirements of the accounting standard update on revenue from contracts with customers following the modified retrospective method, as further discussed in this note, as well as in Note 2. As such, results for reporting periods beginning January 1, 2018, are presented under the new guidance, while prior period amounts are not adjusted and continue to be reported in accordance with the historic accounting for revenue recognition. Based on the Company's analysis, the Company did not identify a significant change in the timing of revenue recognition under the new guidance as compared to the historic accounting for revenue recognition.

Certain prior year amounts have been reclassified to conform to the current year presentation in the consolidated financial statements related to the retrospective adoption of the accounting standard update to improve the presentation of net periodic pension and net periodic postretirement benefit costs, which was effective on January 1, 2018. The components of net periodic pension and postretirement costs, other than service costs, were reclassified from operating expenses to other income on the Consolidated Statements of Income, as further discussed in this note.

The assets and liabilities for the Company's discontinued operations have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. At the time the assets were classified as held for sale, depreciation, depletion and amortization expense was no longer recorded. Unless otherwise indicated, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's continuing operations. For more information on the Company's discontinued operations, see Note€4.

Management has also evaluated the impact of events occurring after December€31, 2018, 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 Note€2. The total balance of receivables past due 90 days or more was $30.0€million and $34.7€million at December€31, 2018 and 2017, 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 at December€31, 2018 and 2017, was $8.9€million and $8.1€million, respectively.

Accounts receivable also consists of accrued unbilled revenue representing revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $96.2€million and $112.7€million at December€31, 2018 and 2017, respectively.

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

	2018	2017
	(In thousands)	
Short-term retainage*	$ 56,228	$ 57,134
Long-term retainage**	4,152	1,410
Total retainage	$ 60,380	$ 58,544

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

Inventories and natural gas in storage

Natural gas in storage for the Company's regulated operations is generally carried at lower of cost or net realizable value, or cost using the last-in, first-out method. All other inventories are stated at the lower of cost or net realizable value. 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:

	2018	2017
	(In thousands)	
Aggregates held for resale	$ 139,681	$ 115,268
Asphalt oil	54,741	30,360
Materials and supplies	23,611	18,650
Merchandise for resale	22,552	14,905
Natural gas in storage (current)	22,117	20,950
Other	24,607	26,450
Total	$ 287,309	$ 226,583

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 deferred charges and other assets - other and was $48.5 million and $49.3 million at December 31, 2018 and 2017 , respectively.

Investments

The Company's investments include the cash surrender value of life insurance policies, an insurance contract, mortgage-backed securities and U.S. Treasury securities. 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 7 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, 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, on certain construction projects associated with its other operations. The amount of AFUDC for the years ended December 31 were as follows:

	2018	2017	2016
		(In thousands)	
AFUDC - borrowed	$ 2,290	$ 966	$ 914
AFUDC - equity	$ 1,897	$ 909	$ 565

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. The Company collects removal costs for plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities, which are included in deferred credits and other liabilities - other.

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

	2018	2017	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$ 1,131,484	$ 1,034,765	49
Distribution	430,750	415,543	46
Transmission	302,315	296,941	64
Construction in progress	161,893	117,906	„
Other	122,127	117,109	13
Natural gas distribution:			
Distribution	1,981,356	1,831,795	47
Construction in progress	21,028	19,823	„
Other	496,708	468,227	16
Pipeline and midstream:			
Transmission	585,594	516,932	54
Gathering	37,829	37,837	20
Storage	49,101	45,629	61
Construction in progress	5,915	17,488	„
Other	45,763	41,054	33
Nonregulated:			
Pipeline and midstream:			
Gathering and processing	31,094	31,678	19
Construction in progress	86	17	„
Other	9,577	9,649	10
Construction materials and contracting:			
Land	109,541	95,745	„
Buildings and improvements	114,905	102,435	20
Machinery, vehicles and equipment	1,090,790	947,979	12
Construction in progress	22,507	7,750	„
Aggregate reserves	430,263	406,139	*
Construction services:			
Land	5,216	5,216	„
Buildings and improvements	29,795	27,351	25
Machinery, vehicles and equipment	145,859	137,924	6
Other	7,716	6,774	3
Other:			
Land	2,648	2,837	„
Other	25,461	28,286	14
Less accumulated depreciation, depletion and amortization	2,818,644	2,691,641	
Net property, plant and equipment	$ 4,578,677	$ 4,079,188	

* Depleted on the units-of-production method based on recoverable aggregate reserves.

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and assets held for sale, 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. The impairments are recorded in operation and maintenance expense on the Consolidated Statements of Income.

No significant impairment losses were recorded in 2018, 2017 or 2016, other than those related to the Company's assets held for sale and discontinued operations recorded in 2016. For more information regarding these impairments, see Note€4.

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, 2018, 2017 and 2016, there were no impairment losses recorded. At December€31, 2018, 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, risk adjusted 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 risk adjusted cost of capital at each reporting unit. The risk adjusted cost of capital, which varies by reporting unit and is in the range of 5€percent to 9€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 2018. Under the market approach, the Company estimates fair value using multiples derived from 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.

Revenue recognition

Revenue is recognized when a performance obligation is satisfied by transferring control over a product or service to a customer. Revenue is measured based on consideration specified in a contract with a customer, and excludes any sales incentives and amounts collected on behalf of third parties. The Company is considered an agent for certain taxes collected from customers. As such, the Company presents revenues net of these taxes at the time of sale to be remitted to governmental authorities, including sales and use taxes.

The electric and natural gas distribution segments generate revenue from the sales of electric and natural gas products and services, which includes retail and transportation services. These segments establish a customer's retail or transportation service account based on the customer's application/contract for service, which indicates approval of a contract for service. The contract identifies an obligation to provide service in exchange for delivering or standing ready to deliver the identified commodity; and the customer is obligated to pay for the service as provided in the applicable tariff. The product sales are based on a fixed rate that includes a base and per-unit rate, which are included in approved tariffs as determined by state or federal regulatory agencies. The quantity of the commodity consumed or transported determines the total per-unit revenue. The service provided, along with the product consumed or transported, are a single performance obligation because both are required in combination to successfully transfer the contracted product or service to the customer. Revenues are recognized over time as customers receive and consume the products and services. The method of measuring progress toward the completion of the single performance obligation is on a per-unit output method basis, with revenue recognized based on the direct measurement of the value to the customer of the goods or services transferred to date. For contracts governed by the Companyƒs utility tariffs, amounts are billed monthly with the amount due between 15 and 22 days of receipt of the invoice depending on the applicable stateƒs tariff. For other contracts not governed by tariff, payment terms are net 30 days. At this time, the segment has no material obligations for returns, refunds or other similar obligations.

The pipeline and midstream segment generates revenue from providing natural gas transportation, gathering and underground storage services, as well as other energy-related services to both third parties and internal customers, largely the natural gas distribution segment. The pipeline and midstream segment establishes a contract with a customer based upon the customerƒs request for firm or interruptible natural gas transportation, storage or gathering service(s). The contract identifies an obligation for the segment to provide the requested service(s) in exchange for consideration from the customer over a specified term. Depending on the type of service(s) requested and contracted, the service provided may include transporting, gathering or storing an identified quantity of natural gas and/or standing ready to deliver or store an identified quantity of natural gas. Natural gas transportation, gathering and storage revenues are based on fixed rates, which may include reservation fees and/or per-unit commodity rates. The services provided by the segment are generally treated as single performance obligations satisfied over time simultaneous to when the service is provided and revenue is recognized. Rates for the segmentƒs regulated services are based on its FERC approved tariff or customer negotiated rates on special projects, and rates for its non-regulated services are negotiated with its customers and set forth in the contract. For contracts governed by the companyƒs tariff, amounts are billed on or before the ninth business day of the following month and the amount is due within 12 days of receipt of the invoice. For gathering contracts not governed by the tariff, amounts are due within twenty days of invoice receipt. For other contracts not governed by the tariff, payment terms are net 30 days. At this time, the segment has no material obligations for returns, refunds or other similar obligations.

The construction materials and contracting segment generates revenue from contracting services and construction materials sales. This segment focuses on the vertical integration of its contracting services with its construction materials to support the aggregate based product lines. This segment provides contracting services to a customer when a contract has been signed by both the customer and a representative of the segment obligating a service to be provided in exchange for the consideration identified in the contract. The nature of the services this segment provides generally includes integrating a set of services and related construction materials into a single project to create a distinct bundle of goods and services, which the Company evaluates to determine whether a separate performance obligation exists. The transaction price is the original contract price plus any subsequent change orders and variable consideration. Examples of variable consideration that exist in this segment's contracts include liquidated damages; performance bonuses or incentives and penalties; claims; unapproved/unpriced change orders; and index pricing. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using estimation methods that best predict the most likely amount of consideration the Company expects to be entitled to or expects to incur. The Company includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis. Revenue is recognized over time using the input method based on the measurement of progress on a project. The input method is the preferred method of measuring revenue because the costs incurred have been determined to represent the best indication of the overall progress toward the transfer of such goods or services promised to a customer. This segment also sells construction materials to third parties and internal customers. The contract for material sales is the use of a sales order or an invoice, which includes the pricing and payment terms. All material contracts contain a single performance obligation for the delivery of a single distinct product or a distinct separately identifiable bundle of products and services. Revenue is recognized at a point in time when the performance obligation has been satisfied with the delivery of the products or services. The warranties associated with the sales are those consistent with a standard warranty that the product meets certain specifications for quality or those required by law. For most contracts, amounts billed to customers are due within 30 days of receipt. There are no material obligations for returns, refunds or other similar obligations.

The construction services segment generates revenue from specialty contracting services which also includes the sale of construction equipment and other supplies. This segment provides specialty contracting services to a customer when a contract has been signed by both the customer and a representative of the segment obligating a service to be provided in exchange for the consideration identified in the contract. The nature of the services this segment provides generally includes multiple promised goods and services in a single project to create a distinct bundle of goods and services, which the Company evaluates to determine whether a separate performance obligation exists. The transaction price is the original contract price plus any subsequent change orders and variable consideration. Examples of variable consideration that exist in this segment's contracts include claims, unapproved/unpriced change orders, bonuses, incentives, penalties and liquidated damages. The variable amounts usually arise upon achievement of certain performance metrics or change in project scope. The Company estimates the amount of revenue to be recognized on variable consideration using estimation methods that best predict the most likely amount of consideration the Company expects to be entitled to or expects to incur. The Company includes variable consideration in the estimated transaction price to the extent it is probable that a significant reversal of cumulative revenue recognized will not occur or when the uncertainty associated with the variable consideration is resolved. Changes in circumstances could impact management's estimates made in determining the value of variable consideration recorded. The Company updates its estimate of the transaction price each reporting period and the effect of variable consideration on the transaction price is recognized as an adjustment to revenue on a cumulative catch-up basis. Revenue is recognized over time using the input method based on the measurement of progress on a project. The input method is the preferred method of measuring revenue because the costs incurred have been determined to represent the best indication of the overall progress toward the transfer of such goods or services promised to a customer. This segment also sells construction equipment and other supplies to third parties and internal customers. The contract for these sales is the use of a sales order or invoice, which includes the pricing and payment terms. All such contracts include a single performance obligation for the delivery of a single distinct product or a distinct separately identifiable bundle of products and services. Revenue is recognized at a point in time when the performance obligation has been satisfied with the delivery of the products or services. The warranties associated with the sales are those consistent with a standard warranty that the product meets certain specifications for quality or those required by law. For most contracts, amounts billed to customers are due within 30 days of receipt. There are no material obligations for returns, refunds or other similar obligations.

The Company recognizes all other revenues when services are rendered or goods are delivered. For more information on revenue from contracts with customers, see Note 2.

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 9.

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 which are filed annually. Natural gas costs refundable through rate adjustments were $30.0 million and $28.5 million at December 31, 2018 and 2017, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $42.7 million and $14.5 million at December 31, 2018 and 2017, respectively, which is included in prepayments and other current assets.

Stock-based compensation

The Company determines compensation expense for stock-based awards based on the estimated fair values at the grant date and recognizes the related compensation expense over the vesting period. The Company uses the straight-line amortization method to recognize compensation expense related to restricted stock, which only has a service condition. This method recognizes stock compensation expense on a straight-line basis over the requisite service period for the entire award. The Company recognizes compensation expense related to performance awards that vest based on performance metrics and service conditions on a straight-line basis over the service period. Inception-to-date expense is adjusted based upon the determination of the potential achievement of the performance target at each reporting date. The Company recognizes compensation expense related to performance awards with market-based performance metrics on a straight-line basis over the requisite service period.

The Company records the compensation expense for performance share awards using an estimated forfeiture rate. The estimated forfeiture rate is calculated based on an average of actual historical forfeitures. The Company also preforms an analysis of any known factors at the time of the calculation to identify any necessary adjustments to the average historical forfeiture rate. At the time actual forfeitures become more than estimated forfeitures, the Company records compensation expense using actual forfeitures.

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 by using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. 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.

The Company records uncertain tax positions in accordance with accounting guidance on accounting for income taxes on the basis of a two-step process in which (1) the Company determines whether it is more-likely-than-not that the tax position will be sustained on the basis of the technical merits of the position and (2) for those tax positions that meet the more-likely than-not recognition threshold, the Company recognizes the largest amount of the tax benefit that is more than 50 percent likely to be realized upon ultimate settlement with the related tax authority. Tax positions that do not meet the more-likely-than-not criteria are reflected as a tax liability. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

Earnings per common share

Basic earnings per common share were computed by dividing earnings 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 nonvested performance share awards and restricted stock units. Common stock outstanding includes issued shares less shares held in treasury. Earnings on common stock was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculation was as follows:

	2018	2017	2016
		(In thousands)	
Weighted average common shares outstanding - basic	195,720	195,304	195,299
Effect of dilutive performance share awards	430	383	319
Weighted average common shares outstanding - diluted	196,150	195,687	195,618
Shares excluded from the calculation of diluted earnings per share	10	„	„

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 long-lived assets and goodwill; fair values of acquired assets and liabilities under the acquisition method of accounting; aggregate reserves; property depreciable lives; tax provisions; revenue recognized using the cost-to-cost measure of progress for contracts; 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; and the valuation of stock-based compensation. 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.

New accounting standards

Recently adopted accounting standards

ASU 2014-09 - Revenue from Contracts with Customers In May€2014, the FASB issued guidance on accounting for revenue from contracts with customers. The guidance provides for a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry specific guidance. In August€2015, the FASB issued guidance deferring the effective date of the revenue guidance and allowing entities to early adopt. With this decision, the guidance was effective for the Company on January€1, 2018. Entities had the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified retrospective approach, an entity recognizes the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption.

The Company adopted the guidance on January€1, 2018, using the modified retrospective approach. The Company elected the practical expedient to not disclose the aggregate amount of the transaction price allocated to the performance obligations that are unsatisfied (or partially unsatisfied) as of the end of the reporting period, along with an explanation of when such revenue would be expected to be recognized. This practical expedient was used since the performance obligations are part of contracts with an original duration of one year or less. The Company also elected the practical expedient to recognize the incremental costs of obtaining a contract as an expense when incurred if the amortization period of the asset that the Company otherwise would have recognized is one year or less. Upon completion of the Company's evaluation of contracts and methods of revenue recognition under the previous accounting guidance, the Company did not identify any material cumulative effect adjustments to be made to retained earnings. In addition, the Company has expanded revenue disclosures, both quantitatively and qualitatively, related to the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers, as discussed in Note€2. The Company reviewed its revenue streams to evaluate the impact of this guidance and did not identify a significant change in the timing of revenue recognition, results of operations, financial position or cash flows. The Company reviewed its internal controls related to revenue recognition and disclosures and concluded that the guidance impacted certain business processes and controls. As such, the Company developed modifications to its internal controls for certain topics under the guidance as they apply to the Company and such modifications were not deemed to be significant. Results for reporting periods beginning after December€31, 2017, are presented under the new guidance, while prior period amounts are not adjusted and continue to be reported in accordance with historic accounting for revenue recognition.

Under the modified retrospective approach, the guidance was applied only to contracts that were not completed as of January€1, 2018. Therefore, the Company recognized the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings at January€1, 2018. For the twelve months ended December 31, 2018 , there were no material impacts to the financial statements as a result of applying the guidance. The cumulative effect of the changes made to the Consolidated Balance Sheet were as follows:

	December 31, 2017	Adjustments	January 1, 2018
		(In thousands)	
Liabilities and Stockholders' Equity			
Current liabilities:			
Other accrued liabilities	$ 186,010	$ 903	$ 186,913
Deferred credits and other liabilities:			
Deferred income taxes	347,271	(332)	346,939
Other	1,179,140	399	1,179,539
Commitments and contingencies			
Stockholders' equity:			
Common stockholders' equity:			
Retained earnings	1,040,748	(970)	1,039,778

The cumulative effect adjustment is related to prepaid natural gas transportation to storage contracts where a separate performance obligation existed and has not yet been satisfied. As such, these contracts were still open and met the criteria for a cumulative effect adjustment.

ASU 2016-15 - Classification of Certain Cash Receipts and Cash Payments In August€2016, the FASB issued guidance to clarify the classification of certain cash receipts and payments in the statement of cash flows. The guidance is intended to standardize the presentation and classification of certain transactions, including cash payments for debt prepayment or extinguishment, proceeds from insurance claim settlements and distributions from equity method investments. In addition, the guidance clarifies how to classify transactions that have characteristics of more than one class of cash flows. The Company adopted the guidance on January€1, 2018, on a prospective basis. The guidance did not have a material effect on the Company's statement of cash flows.

ASU 2017-01 - Clarifying the Definition of a Business In January€2017, the FASB issued guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The guidance also affects other aspects of accounting, such as determining reporting units for goodwill testing and whether an entity has acquired or sold a business. The Company adopted the guidance on January€1, 2018, on a prospective basis. The guidance did not have a material effect on the Company's results of operations, financial position, cash flows or disclosures.

ASU 2017-07 - Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost In March€2017, the FASB issued guidance to improve the presentation of net periodic pension and net periodic postretirement benefit costs. The guidance required the service cost component to be presented in the income statement in the same line item or items as other compensation costs arising from services performed during the period. Other components of net periodic benefit cost shall be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The guidance also only allows the service cost component to be capitalized.

The Company adopted the guidance on January€1, 2018, on a retrospective basis. The guidance required the reclassification of all components of net periodic benefit costs, except for the service cost component, from operating expenses to other income on the Consolidated Statements of Income with no impact to earnings. As a result of the retrospective application of this change in accounting guidance, the Company reclassified $6.2 million and $4.5 million from operation and maintenance expense to other income on the Consolidated Statements of Income for the years ended December 31, 2017 and 2016, respectively. The Company also reclassified unrealized gains on investments used to satisfy obligations under the defined benefit plans of $10.8 million and $4.7 million for the years ended December 31, 2017 and 2016, respectively, which were included in operation and maintenance expense, to other income on the Consolidated Statements of Income. The guidance did not have a material effect on the Company's results of operations, cash flows or disclosures.

ASU 2018-02 - Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income In February€2018, the FASB issued guidance that allows an entity to reclassify the stranded tax effects resulting from the newly enacted federal corporate income tax rate from accumulated other comprehensive income (loss) to retained earnings. The guidance is effective for the Company on January€1, 2019, including interim periods, with early adoption permitted. The guidance can be applied using one of two methods. One method is to record the reclassification of the stranded income taxes at the beginning of the period of adoption. The other method is to apply the guidance retrospectively to each period in which the income tax effects of the TCJA are recognized in accumulated other comprehensive income (loss). The Company early adopted the guidance on January€1, 2018, and elected to reclassify the stranded income taxes at the beginning of the period. During the first quarter of 2018, the Company reclassified $7.9 million of stranded tax expense from accumulated other comprehensive loss to retained earnings. The guidance did not have a material effect on the Company's results of operations, cash flows or disclosures.

SEC File Number S7-15-16 - Disclosure Update and Simplification In October€2018, the SEC published guidance in the Federal Register on disclosure updates and simplifications. The guidance removed disclosures that are no longer considered cost beneficial, duplicative of GAAP required disclosures, clarified the specific requirements of disclosures and added disclosure requirements identified as relevant. The amendments were intended to facilitate disclosure of information to investors and simplify the compliance without significantly altering the total mix of information provided to investors. The guidance was effective for the Company on November 5, 2018, including interim periods. The Company adopted the guidance in the Annual Report on Form 10-K for the year ended December 31, 2018, which required minimal disclosure updates. The guidance was applied on a prospective basis and did not have a material effect on the Company's disclosures or certain sections of the Annual Report on Form 10-K.

Recently issued accounting standards not yet adopted

ASU 2016-02 - Leases In February€2016, the FASB issued guidance regarding leases. The guidance requires lessees to recognize a lease liability and a right-of-use asset on the balance sheet for operating and financing leases. The guidance remains largely the same for lessors, although some changes were made to better align lessor accounting with the new lessee accounting and to align with the revenue recognition standard. The guidance also requires additional disclosures, both quantitative and qualitative, related to operating and finance leases for the lessee and sales-type, direct financing and operating leases for the lessor. The Company adopted the standard on January€1, 2019.

In July€2018, the FASB issued ASU 2018-11 - Leases: Targeted Improvements, an accounting standard update to ASU 2016-02. This ASU provides an entity the option to adopt the guidance using one of two modified retrospective approaches. An entity can adopt the guidance using the modified retrospective transition approach beginning in the earliest year presented in the financial statements. This method of adoption would require the restatement of prior periods reported and the presentation of lease disclosures under the new guidance for all periods reported. The additional transition method of adoption introduced by ASU 2018-11, allows entities the option to apply the guidance on the date of adoption by recognizing a cumulative effect adjustment to retained earnings during the period of adoption and does not require prior comparative periods to be restated. The Company adopted the standard on January€1, 2019, utilizing the practical expedient that allows the Company to not reassess whether an expired or existing contract contains a lease, the classification of leases or initial direct costs, as well as the additional transition method of adoption applied on the date of adoption. The Company also adopted a short-term leasing policy as the lessee where leases with a term of 12 months or less will not be included on the Consolidated Balance Sheet.

In January€2018, the FASB issued a practical expedient for land easements under the new lease guidance. The practical expedient permits an entity to elect the option to not evaluate land easements under the new guidance if they existed or expired before the adoption of the new lease guidance and were not previously accounted for as leases under the previous lease guidance. Once an entity adopts the new guidance, the entity should apply the new guidance on a prospective basis to all new or modified land easements. The Company has adopted this practical expedient. The Company will evaluate any new or modified agreements that fall within the scope of the standard. The Company continues to monitor other industry-specific issues as it relates to its regulated businesses but does not expect these issues to have a material impact on the Company's results of operations, financial position or disclosures.

The Company formed a lease implementation team to review and assess existing contracts to identify and evaluate those containing leases. Additionally, the team has implemented new and revised existing software to meet the reporting and disclosure requirements of the standard. The Company also has assessed the impact the standard will have on its processes and internal controls and has identified new and updated existing internal controls and processes to ensure compliance with the new lease standard; such modifications were not deemed to be significant. During the assessment phase, the Company used various surveys, reconciliations and analytic methodologies to ensure the completeness of the lease inventory. The Company determined that most of the current operating leases are subject to the guidance and will be recognized as operating lease liabilities and right-of-use assets on the Consolidated Balance Sheets upon adoption. The Company expects the impact of the lessee guidance to be approximately $105 million to $125 million of an increase to assets and liabilities on January 1, 2019. In addition, the Company has evaluated the impact the new guidance will have on lease contracts where the Company is the lessor and does not anticipate a significant impact.

ASU 2017-04 - Simplifying the Test for Goodwill Impairment In January€2017, the FASB issued guidance on simplifying the test for goodwill impairment by eliminating Step€2, which required an entity to measure the amount of impairment loss by comparing the implied fair value of reporting unit goodwill with the carrying amount of such goodwill. This guidance requires entities to perform a quantitative impairment test, previously Step€1, to identify both the existence of impairment and the amount of impairment loss by comparing the fair value of a reporting unit to its carrying amount. Entities will continue to have the option of performing a qualitative assessment to determine if the quantitative impairment test is necessary. The guidance also requires additional disclosures if an entity has one or more reporting units with zero or negative carrying amounts of net assets. The guidance will be effective for the Company on January€1, 2020, and must be applied on a prospective basis with early adoption permitted. The Company does not expect the guidance to have a material impact on its results of operations, financial position, cash flows and disclosures.

ASU 2018-13 - Changes to the Disclosure Requirements for Fair Value Measurement In August€2018, the FASB issued guidance on modifying the disclosure requirements on fair value measurements as part of the disclosure framework project. The guidance modifies, among other things, the disclosures required for Level 3 fair value measurements, including the range and weighted average of significant unobservable inputs. The guidance removes, among other things, the disclosure requirement to disclose transfers between Levels 1 and 2. The guidance will be effective for the Company on January€1, 2020, including interim periods, with early adoption permitted. Level 3 fair value measurement disclosures should be applied prospectively while all other amendments should be applied retrospectively. The Company is evaluating the effects the adoption of the new guidance will have on its disclosures.

ASU 2018-14 - Changes to the Disclosure Requirements for Defined Benefit Plans In August€2018, the FASB issued guidance on modifying the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans as part of the disclosure framework project. The guidance removes disclosures that are no longer considered cost beneficial, clarifies the specific requirements of disclosures and adds disclosure requirements identified as relevant. The guidance adds, among other things, the requirement to include an explanation for significant gains and losses related to changes in benefit obligations for the period. The guidance removes, among other things, the disclosure requirement to disclose the amount of net periodic benefit costs to be amortized over the next fiscal year from accumulated other comprehensive income (loss) and the effects a one percentage point change in assumed health care cost trend rates will have on certain benefit components. The guidance will be effective for the Company on January€1, 2021, and must be applied on a retrospective basis with early adoption permitted. The Company is evaluating the effects the adoption of the new guidance will have on the its disclosures.

ASU 2018-15 - Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement that is a Service Contract In August€2018, the FASB issued guidance on the accounting for implementation costs of a hosting arrangement that is a service contract. The guidance aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract similar to the costs incurred to develop or obtain internal-use software and such capitalized costs to be expensed over the term of the hosting arrangement. Costs incurred during the preliminary and postimplementation stages should continue to be expensed as activities are performed. The capitalized costs are required to be presented on the balance sheet in the same line the prepayment for the fees associated with the hosting arrangement would be presented. In addition, the expense related to the capitalized implementation costs should be presented in the same line on the income statement as the fees associated with the hosting element of the arrangements. The guidance will be effective for the Company on January€1, 2020, including interim periods, and may be applied on a retrospective or a prospective basis with early adoption permitted. The Company adopted the guidance effective January 1, 2019, on a prospective basis. The adoption of the guidance will not have a material impact on its results of operations, financial position, cash flows and disclosures.

ASU 2018-18 - Clarifying the Interaction between Topic 808 and Topic 606 In November€2018, the FASB issued guidance on whether certain transactions between collaborative arrangement participants should be accounted for within revenue under Topic 606 in order to provide for better comparability among entities. The guidance clarifies which transactions should be accounted for as revenue under Topic 606 and provides unit-of-account guidance in Topic 808 to align with the guidance in Topic 606 regarding distinct goods or services. The guidance also specifies that transactions with a collaborative arrangement not directly related to sales to third parties may not be presented together with revenue recognized under Topic 606. The guidance will be effective for the Company on January 1, 2020, including interim periods, and must be applied retrospectively to January 1, 2018, the date in which the Company adopted Topic 606. An entity may apply the guidance to either all contracts or to only contracts that are not completed as of the date of the initial application of Topic 606. The Company is evaluating the effects the adoption of the new guidance will have on the its results of operations, financial position, cash flows and disclosures.

SEC Final Rulemaking Release Number 33-10570 - Modernization of Property Disclosures for Mining Registrants In November€2018, the SEC published guidance in the Federal Register on the modernization of property disclosures for mining registrants. The guidance requires additional disclosures related to activities under material mining operations to be included as an exhibit, including a technical report summary by a qualified person about an organization's mineral resources or mineral reserves; an overview of mining properties and operations; a summary of all mineral resources and mineral reserves as of the most recently completed fiscal year; a description of each material property, including the proposed program of exploration and development, stage of the development or production, and current production activities, among other things; and a description of the organization's internal controls surrounding mineral resource and reserve estimates. The guidance will be effective on a prospective basis for the Company on January 1, 2021, including interim periods, with early adoption permitted. The Company is evaluating the effects the adoption of the guidance will have on its disclosures in the Annual Report on Form 10-K.

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 losses on derivative instruments qualifying as hedges, postretirement liability adjustments, foreign currency translation adjustments and loss on available-for-sale investments.

The after-tax changes in the components of accumulated other comprehensive loss as of December€31, 2018, 2017 and 2016, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Post-retirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
			(In thousands)		
Balance at December€31, 2016	$ (2,300)	$ (33,221)	$ (149)	$ (63)	$ (35,733)
Other comprehensive loss before reclassifications	„	(1,812)	(6)	(139)	(1,957)
Amounts reclassified from accumulated other comprehensive loss	366	1,013	„	120	1,499
Amounts reclassified to accumulated other comprehensive loss from a regulatory asset	„	(1,143)	„	„	(1,143)
Net current-period other comprehensive income (loss)	366	(1,942)	(6)	(19)	(1,601)
Balance at December€31, 2017	(1,934)	(35,163)	(155)	(82)	(37,334)
Other comprehensive income (loss) before reclassifications	„	4,441	(61)	(144)	4,236
Amounts reclassified from accumulated other comprehensive loss	162	2,173	249	131	2,715
Net current-period other comprehensive income (loss)	162	6,614	188	(13)	6,951
Reclassification adjustment of prior period tax effects related to TCJA included in accumulated other comprehensive loss	(389)	(7,520)	(33)	(17)	(7,959)
Balance at December€31, 2018	$ (2,161)	$ (36,069)	$ •	$ (112)	$ (38,342)

The following amounts were reclassified out of accumulated other comprehensive loss into net income. The amounts presented in parenthesis indicate a decrease to net income on the Consolidated Statements of Income. The reclassifications for the years ended December€31 were as follows:

	2018	2017	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for loss on derivative instruments included in net income	$ (591)	$ (590)	Interest expense
	429	224	Income taxes
	(162)	(366)	
Amortization of postretirement liability losses included in net periodic benefit cost (credit)	(2,894)	(1,658)	Other income
	721	645	Income taxes
	(2,173)	(1,013)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net income	(324)	„	Other income
	75	„	Income taxes
	(249)	„	
Reclassification adjustment for loss on available-for-sale investments included in net income	(166)	(185)	Other income
	35	65	Income taxes
	(131)	(120)	
Total reclassifications	$ (2,715)	$ (1,499)	

Note 2 - Revenue from Contracts with Customers

Disaggregation

In the following table, revenue is disaggregated by the type of customer or service provided. The Company believes this level of disaggregation best depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors. The table also includes a reconciliation of the disaggregated revenue by reportable segments. For more information on the Company's business segments, see Note 15.

Year ended December 31, 2018	Electric	Natural gas distribution	Pipeline and midstream	Construction materials and contracting	Construction services	Other	Total
				(In thousands)			
Residential utility sales	$ 121,477	$ 457,959	$ —	$ —	$ —	$ —	$ 579,436
Commercial utility sales	136,236	276,716	—	—	—	—	412,952
Industrial utility sales	34,353	24,603	—	—	—	—	58,956
Other utility sales	7,556	—	—	—	—	—	7,556
Natural gas transportation	—	43,238	89,159	—	—	—	132,397
Natural gas gathering	—	—	9,159	—	—	—	9,159
Natural gas storage	—	—	11,543	—	—	—	11,543
Contracting services	—	—	—	968,755	—	—	968,755
Construction materials	—	—	—	1,423,068	—	—	1,423,068
Intrasegment eliminations*	—	—	—	(465,969)	—	—	(465,969)
Inside specialty contracting	—	—	—	—	926,875	—	926,875
Outside specialty contracting	—	—	—	—	392,544	—	392,544
Other	31,568	14,579	18,865	—	525	11,259	76,796
Intersegment eliminations	—	—	(50,905)	(669)	(1,681)	(11,052)	(64,307)
Revenues from contracts with customers	331,190	817,095	77,821	1,925,185	1,318,263	207	4,469,761
Revenues out of scope	3,933	6,152	197	—	51,509	—	61,791
Total external operating revenues	$ 335,123	$ 823,247	$ 78,018	$ 1,925,185	$ 1,369,772	$ 207	$ 4,531,552

* Intrasegment revenues are presented within the construction materials and contracting segment to highlight the focus on vertical integration as this segment sells materials to both third parties and internal customers. Due to consolidation requirements, these revenues must be eliminated against construction materials to arrive at the external operating revenue total for the segment.

Contract balances

The timing of revenue recognition may differ from the timing of invoicing to customers. The timing of invoicing to customers does not necessarily correlate with the timing of revenues being recognized under the cost-to-cost method of accounting. Contracts from contracting services are billed as work progresses in accordance with agreed upon contractual terms. Generally, billing to the customer occurs contemporaneous to revenue recognition. A variance in timing of the billings may result in a contract asset or a contract liability. A contract asset occurs when revenues are recognized under the cost-to-cost measure of progress, which exceeds amounts billed on uncompleted contracts. Such amounts will be billed as standard contract terms allow, usually based on various measures of performance or achievement. A contract liability occurs when there are billings in excess of revenues recognized under the cost-to-cost measure of progress on uncompleted contracts. Contract liabilities decrease as revenue is recognized from the satisfaction of the related performance obligation. The changes in contract assets and liabilities were as follows:

	December 31, 2018	December 31, 2017	Change	Location on Consolidated Balance Sheets
	(In thousands)			
Contract assets	$ 104,239	$ 109,540	$ (5,301)	Receivables, net
Contract liabilities - current	(93,901)	(84,123)	(9,778)	Accounts payable
Contract liabilities - noncurrent	(135)	—	(135)	Deferred credits and other liabilities - other
Net contract assets	$ 10,203	$ 25,417	$ (15,214)	

At December 31, 2018, the Company's net contract assets decreased $15.2 million compared to December 31, 2017. Included in the change of total net contract assets was a decrease in contract assets due to revenue recognized in excess of billings on contracts and an increase in contract liabilities due to billings on contracts in excess of revenues recognized. The Company recognized $78.6 million in revenue for the year ended December 31, 2018, which was previously included in contract liabilities at December 31, 2017.

The Company recognized a net increase in revenues of $36.7 million for the year ended December 31, 2018, from performance obligations satisfied in prior periods.

Note 3 - Acquisitions

During 2018, the Company completed four acquisitions. The results of the acquired businesses have been included in the Company's construction materials and contracting segment and Consolidated Financial Statements beginning on the acquisition dates. Pro forma financial amounts reflecting the effects of the above acquisitions are not presented, as such acquisitions were not material, both individually and in the aggregate, to the Company's financial position or results of operations. The following is a listing of the acquisitions made during 2018:

- In April 2018, the Company acquired Teevin & Fischer Quarry, LLC, an aggregate producer that provides crushed rock and gravel to construction and retail customers in Oregon.
- In June 2018, the Company acquired Tri-City Paving, Inc., a general contractor and aggregate, asphalt and ready-mixed concrete supplier in Minnesota.
- In July 2018, the Company acquired Molalla Redi-Mix and Rock Products, Inc., a producer of ready-mixed concrete in Oregon.
- In October 2018, the Company acquired Sweetman Construction Company, a provider of aggregates, asphalt and ready-mixed concrete in South Dakota.

As of December 31, 2018, the gross aggregate consideration for these acquisitions, which were all accounted for as business combinations, was $168.1 million in cash, subject to certain adjustments, and 721,610 shares of common stock with a market value of $20.3 million as of the respective acquisition date. Due to the holding period restriction on the common stock, the share consideration has been discounted to a fair value of approximately $18.2 million, as reflected in the Company's financial statements. In addition to the issuance of the Company's equity securities, the Company issued debt to finance these acquisitions. As of December 31, 2018, costs incurred for acquisitions were $1.5 million and included in operation and maintenance expense on the Consolidated Statements of Income. The acquisitions are subject to customary adjustments based on, among other things, the amount of cash, debt and working capital in the businesses as of the closing dates.

The Company preliminarily allocated the purchase price of the acquisitions to the assets acquired and liabilities assumed based on their estimated fair values as of the acquisition dates and are considered provisional until final fair values are determined or the measurement period has passed. The Company expects to record adjustments as it accumulates the information needed to estimate the fair value of assets acquired and liabilities assumed, including working capital balances, estimated fair value of identifiable intangible assets, property, plant and equipment, total consideration and goodwill. The excess of the purchase price over the aggregate fair values was recorded as goodwill. The Company calculated the fair value of the assets acquired using the market or cost approach (or a combination of both). Fair values for some of the assets were determined based on Level 3 inputs including estimated future cash flows, discount rates, growth rates, sales projections, retention rates and terminal values, all of which require significant management judgment and are susceptible to change. The final fair value of the net assets acquired may result in adjustments to the assets and liabilities, including goodwill, and will be made as soon as practical, but no later than one year from the respective acquisition dates. However, any subsequent measurement period adjustments are not expected to have a material impact on the Company's results of operations. The discount rate used in calculating the fair value of the common stock issued was determined by a Black-Scholes-Merton model. The model used Level 2 inputs including risk-free interest rate, volatility range and dividend yield.

The aggregate total consideration for the acquisitions and the preliminary amounts allocated to the assets acquired and liabilities assumed based on the estimated fair values as of the respective acquisition dates were as follows:

	2018 Acquisitions
	(In thousands)
Assets	
Current assets:	
Receivables, net	$ 18,984
Inventories	10,329
Other current assets	515
Total current assets	29,828
Property, plant and equipment	131,766
Deferred charges and other assets:	
Goodwill	33,131
Other intangible assets, net	8,227
Other	927
Total deferred charges and other assets	42,285
Total assets acquired	$ 203,879
Liabilities	
Current liabilities	$ 11,122
Deferred credits and other liabilities:	
Asset retirement obligation	914
Deferred income taxes	5,565
Total deferred credits and other liabilities	6,479
Total liabilities assumed	$ 17,601
Total consideration (fair value)	$ 186,278

Note 4 - Discontinued Operations

The assets and liabilities of the Company's discontinued operations have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. At the time the assets were classified as held for sale, depreciation, depletion and amortization expense was no longer recorded.

Dakota Prairie Refining On June 24, 2016, WBI Energy entered into a membership interest purchase agreement with Tesoro to sell all of the outstanding membership interests in Dakota Prairie Refining to Tesoro. WBI Energy and Calumet each previously owned 50 percent of the Dakota Prairie Refining membership interests and were equal members in building and operating Dakota Prairie Refinery. To effectuate the sale, WBI Energy acquired Calumet's 50 percent membership interest in Dakota Prairie Refining on June 27, 2016. The sale of the membership interests to Tesoro closed on June 27, 2016. The sale of Dakota Prairie Refining reduced the Company's risk by decreasing exposure to commodity prices.

In connection with the sale of Dakota Prairie Refining, Centennial guaranteed certain debt obligations of Dakota Prairie Refining and Tesoro agreed to indemnify Centennial for any losses and litigation expenses arising for the guarantee. On October 17, 2018, Centennial was released of any further liabilities or obligations under this guarantee. For more information related to the guarantee, see Note 19.

The carrying amounts of the major classes of assets and liabilities classified as held for sale, related to the operations of and activity associated with Dakota Prairie Refining, on the Company's Consolidated Balance Sheets at December€31 were as follows:

	2018	2017
	(In thousands)	
Assets		
Current assets:		
Income taxes receivable*	$ •	$ 1,778
Total current assets held for sale	•	1,778
Total assets held for sale	$ •	$ 1,778
Liabilities		
Deferred credits and other liabilities:		
Deferred income taxes**	$ •	$ 37
Total noncurrent liabilities held for sale	•	37
Total liabilities held for sale	$ •	$ 37

* On the Company's Consolidated Balance Sheets, these amounts were reclassified to taxes payable and are reflected in current liabilities held for sale.
** On the Company's Consolidated Balance Sheets, these amounts were reclassified to deferred charges and other assets - deferred income taxes and are reflected in noncurrent assets held for sale.

The Company retained certain liabilities of Dakota Prairie Refining which were reflected in current liabilities held for sale on the Consolidated Balance Sheet at December€31, 2016. In the first quarter of 2017, the Company recorded a reversal of a previously accrued liability of $7.0 million ($4.3 million after tax) due to the resolution of a legal matter. As of December 31, 2018, Dakota Prairie Refining incurred no material exit and disposal costs, and does not expect to incur any future material exit and disposal costs.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the second quarter of 2016, the fair value assessment was determined using the market approach based on the sale transaction to Tesoro. The fair value assessment indicated an impairment based on the carrying value exceeding the fair value, which resulted in the Company recording an impairment of $251.9€million ($156.7€million after tax) in the quarter ended June€30, 2016. The impairment was included in operating expenses from discontinued operations. The fair value of Dakota Prairie Refining's assets have been categorized as Level€3 in the fair value hierarchy.

Fidelity In the second quarter of 2015, the Company began the marketing and sale process of Fidelity with an anticipated sale to occur within one year. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell substantially all of Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. In July 2018, the Company completed the sale of a majority of the remaining property, plant and equipment. The sale of Fidelity was part of the Company's strategic plan to grow its capital investments in the remaining business segments and to focus on creating a greater long-term value.

The carrying amounts of the major classes of assets and liabilities classified as held for sale, related to the operations of Fidelity, on the Company's Consolidated Balance Sheets at December€31 were as follows:

	2018	2017
	(In thousands)	
Assets		
Current assets:		
Receivables, net	$ 430	$ 479
Total current assets held for sale	430	479
Noncurrent assets:		
Net property, plant and equipment	•	1,631
Deferred income taxes	1,926	2,637
Other	161	161
Total noncurrent assets held for sale	2,087	4,429
Total assets held for sale	$ 2,517	$ 4,908
Liabilities		
Current liabilities:		
Accounts payable	$ 80	$ 30
Taxes payable	1,451	10,857
Other accrued liabilities	2,470	2,884
Total current liabilities held for sale	4,001	13,771
Total liabilities held for sale	$ 4,001	$ 13,771

At December€31, 2018 and 2017, the Companyƒs deferred tax assets included in assets held for sale were largely comprised of $1.9€million and $2.6€million, respectively, of federal and state net operating loss carryforwards and state alternative minimum tax credits. The Company realized substantially all of the outstanding net operating loss carryforwards from prior periods in 2017.

At December 31, 2017, the Company had federal income tax net operating loss carryforwards and various state income tax net operating loss carryforwards of $4.4€million and $13.8€million, respectively. At December 31, 2018, the Company had no federal or state income tax net operating loss carryforwards.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the first quarter of 2016, the fair value assessment was determined using the market approach largely based on a purchase and sale agreement. The estimated fair value exceeded the carrying value and the Company recorded an impairment reversal of $1.4 million ($900,000 after tax) in the first quarter of 2016. In the second quarter of 2016, the fair value assessment was determined using the income and market approaches. The income approach was determined by using the present value of future estimated cash flows. The market approach was based on market transactions of similar properties. The estimated carrying value exceeded the fair value and the Company recorded an impairment of $900,000 ($600,000 after tax) in the second quarter of 2016.

The Company has incurred $10.5€million of exit and disposal costs to date and has incurred no exit or disposal costs in 2018. The Company does not expect to incur any additional material exit and disposal costs in connection with Fidelity. The exit and disposal costs are associated with severance and other related matters and exclude the office lease expiration discussed in the following paragraph.

Fidelity vacated its office space in Denver, Colorado in 2016. The Company incurred lease payments of approximately $900,000 in 2016. Lease termination payments of $3.2€million were made during the second quarter of 2016. Existing office furniture and fixtures were relinquished to the lessor in the second quarter of 2016.

Dakota Prairie Refining and Fidelity The reconciliation of the major classes of income and expense constituting pretax income (loss) from discontinued operations, which includes Dakota Prairie Refining and Fidelity, to the after-tax income (loss) from discontinued operations on the Company's Consolidated Statements of Income for the years ended December€31 were as follows:

	2018	2017	2016
		(In thousands)	
Operating revenues	$ (459)	$ 465	$ 123,024
Operating expenses	921	(4,607)	513,813
Operating income (loss)	(1,380)	5,072	(390,789)
Other income (expense)	12	(13)	306
Interest expense	575	250	1,753
Income (loss) from discontinued operations before income taxes	(1,943)	4,809	(392,236)
Income taxes*	(4,875)	8,592	(91,882)
Income (loss) from discontinued operations	2,932	(3,783)	(300,354)
Loss from discontinued operations attributable to noncontrolling interest	•	„	(131,691)
Income (loss) from discontinued operations attributable to the Company	$ 2,932	$ (3,783)	$ (168,663)

* Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.

The pretax income (loss) from discontinued operations attributable to the Company, related to the operations of and activity associated with Dakota Prairie Refining, was $(7,000), $6.9€million and $(253.5)€million for the years ended December€31, 2018, 2017 and 2016, respectively.

Note€5 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December€31, 2018, were as follows:

	Balance at January€1, 2018	Goodwill Acquired During the Year	Balance at December€31, 2018
		(In thousands)	
Natural gas distribution	$ 345,736	$ „	$ 345,736
Construction materials and contracting	176,290	33,131	209,421
Construction services	109,765	„	109,765
Total	$ 631,791	$ 33,131	$ 664,922

The changes in the carrying amount of goodwill for the year ended December€31, 2017, were as follows:

	Balance at January€1, 2017	Goodwill Acquired During the Year	Balance at December€31, 2017
		(In thousands)	
Natural gas distribution	$ 345,736	$ „	$ 345,736
Construction materials and contracting	176,290	„	176,290
Construction services	109,765	„	109,765
Total	$ 631,791	$ „	$ 631,791

During 2018, the Company completed four acquisitions and the results of the acquired businesses have been included in the Company's construction materials and contracting segment. At December 31, 2018, the construction materials and contracting segment's goodwill increased by $33.1 million and other intangible assets increased by $8.2 million for these acquisitions. For more information about these acquisitions, see Note 3.

Other amortizable intangible assets at December 31 were as follows:

	2018	2017
	(In thousands)	
Customer relationships	$ 22,720	$ 15,248
Less accumulated amortization	13,535	13,382
	9,185	1,866
Noncompete agreements	2,605	2,430
Less accumulated amortization	1,956	1,805
	649	625
Other	6,458	6,990
Less accumulated amortization	5,477	5,644
	981	1,346
Total	$ 10,815	$ 3,837

Amortization expense for amortizable intangible assets for the years ended December 31, 2018, 2017 and 2016, was $1.2 million, $2.0 million and $2.5 million, respectively. The amounts of estimated amortization expense for identifiable intangible assets as of December 31, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Amortization expense	$ 1,856	$ 1,486	$ 1,096	$ 1,072	$ 1,006	$ 4,299

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 *	2018	2017
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	$ 165,898	$ 163,896
Asset retirement obligations (a)	Over plant lives	60,097	56,078
Natural gas costs recoverable through rate adjustments (b)	Up to 1 year	42,652	14,465
Taxes recoverable from customers (a)	Over plant lives	11,946	12,073
Manufactured gas plant sites remediation (a)	-	16,504	18,213
Long-term debt refinancing costs (a)	Up to 19 years	4,898	5,563
Costs related to identifying generation development (a)	Up to 8 years	2,508	2,960
Other (a) (b)	Up to 20 years	35,614	27,715
Total regulatory assets		340,117	300,963
Regulatory liabilities:			
Taxes refundable to customers (c)		277,833	279,668
Plant removal and decommissioning costs (c)		173,143	176,190
Natural gas costs refundable through rate adjustments (d)		29,995	28,514
Pension and postretirement benefits (c)		15,264	16,021
Other (c) (d)		25,197	18,905
Total regulatory liabilities		521,432	519,298
Net regulatory position		$ (181,315)	$ (218,335)

* Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.
(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 deferred credits and other liabilities - other on the Consolidated Balance Sheets.
(d) Included in other accrued liabilities on the Consolidated Balance Sheets.
(e) Recovered as expense is incurred or cash contributions are made.

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. As of December 31, 2018 and 2017, approximately $313.5 million and $269.1 million, respectively, of regulatory assets were not earning a rate of return.

In the fourth quarter of 2017, the Company performed a one-time revaluation of the Company's regulated deferred tax assets and liabilities for the reduction of the corporate tax rate from 35 percent to 21 percent effective January 1, 2018, as identified in the TCJA. In the fourth quarter of 2017, the revaluation of the deferred tax assets and liabilities resulted in a decrease of $15.5 million in taxes recoverable from customers and an increase of $270.0 million in taxes refundable to customers. The revaluation of the Company's regulatory deferred tax assets and liabilities were deferred as the Company worked with the various regulators to plan for amounts expected to be returned to customers. All amounts related to the TCJA are reserved or passed back to customers. The Company has tax settlements in place in most jurisdictions, with new rates in place in 2018 or expected to be in place in the first half of 2019. TCJA filings are pending in Wyoming and Oregon. For more information on the various rate cases, see Note 18. There were no significant changes between the preliminary estimate and final determination of taxes refundable to or recoverable from customers. These regulatory amounts will largely be refunded over the remaining life of the related assets.

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 or accumulated other comprehensive income (loss) in the period in which the discontinuance of regulatory accounting occurs.

Note 7 - 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 $73.8 million and $77.4 million at December 31, 2018 and 2017, respectively, are classified as investments on the Consolidated Balance Sheets. The net unrealized loss on these investments for the year ended December 31, 2018, was $3.6 million. The net unrealized gains on these investments for the years ended December 31, 2017 and 2016, were $9.3 million and $3.4 million, respectively. The change in fair value, which is considered part of the cost of the plan, is classified in other income on the Consolidated Statements of Income. In connection with the adoption of ASU 2017-07, as discussed in Note 1, the Company has elected to reclassify prior period unrealized gains from operation and maintenance expense to other income 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, 2018	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$ 10,473	$ 21	$ 162	$ 10,332
U.S. Treasury securities	179	—	—	179
Total	$ 10,652	$ 21	$ 162	$ 10,511

December 31, 2017	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Mortgage-backed securities	$ 10,342	$ 4	$ 129	$ 10,217
U.S. Treasury securities	205	—	1	204
Total	$ 10,547	$ 4	$ 130	$ 10,421

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 are valued at the net asset value of shares held at the end of the period, based on published market quotations on active markets, or using other known sources including pricing from outside sources. 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.

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, 2018 and 2017 , there were no transfers between Levels€1 and 2.

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

	Fair Value Measurements at December€31, 2018, 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, 2018
		(In thousands)		
Assets:				
Money market funds	$ „	$ 10,799	$ „	$ 10,799
Insurance contract*	„	73,838	„	73,838
Available-for-sale securities:				
Mortgage-backed securities	„	10,332	„	10,332
U.S. Treasury securities	„	179	„	179
Total assets measured at fair value	$ „	$ 95,148	$ „	$ 95,148

* The insurance contract invests approximately 53€percent in fixed-income investments, 21€percent in common stock of large-cap companies, 11€percent in common stock of mid-cap companies, 10€percent in common stock of small-cap companies, 3€percent in target date investments and 2€percent in cash equivalents.

	Fair Value Measurements at December€31, 2017, 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, 2017
		(In thousands)		
Assets:				
Money market funds	$ „	$ 6,965	$ „	$ 6,965
Insurance contract*	„	77,388	„	77,388
Available-for-sale securities:				
Mortgage-backed securities	„	10,217	„	10,217
U.S. Treasury securities	„	204	„	204
Total assets measured at fair value	$ „	$ 94,774	$ „	$ 94,774

* The insurance contract invests approximately 49€percent in fixed-income investments, 23€percent in common stock of large-cap companies, 14€percent in common stock of mid-cap companies, 11€percent in common stock of small-cap companies, 2 percent in target date investments and 1€percent in cash equivalents.

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, whenever events or changes in circumstances indicate that such carrying amounts may not be recoverable.

The Company performed a fair value assessment of the assets acquired and liabilities assumed in the business combinations that occurred during 2018. For more information on these Level€2 and Level€3 fair value measurements, see Note 3.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. For more information on these Level€3 nonrecurring fair value measurements, see Note 4€

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:

	2018		2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	$ 2,108,695	$ 2,183,819	$ 1,714,853	$ 1,826,256

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

Note 8 - 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. At December 31, 2018, the Company and its subsidiaries, as applicable, complied with all applicable financial covenants and restrictions. 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, 2018	Amount Outstanding at December 31, 2017	Letters of Credit at December 31, 2018	Expiration Date
				(In millions)		
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$ 175.0	$ 48.5	$ 73.8 (b)	$ —	6/8/23
Cascade Natural Gas Corporation	Revolving credit agreement	$ 75.0 (c)	$ 53.8	$ 17.3	$ 2.2 (d)	4/24/20
Intermountain Gas Company	Revolving credit agreement	$ 85.0 (e)	$ 56.3	$ 40.0	$ —	4/24/20
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (f)	$ 500.0	$ 289.6 (b)	$ 14.6 (b)	$ —	9/23/21

(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 $225.0 million). The amount outstanding under the revolving credit agreement was $48.5 million.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $100.0 million.
(d) Outstanding letter(s) of credit reduce the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $110.0 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 $600.0 million). There were no amounts outstanding under the revolving 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.

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. The Company's ratio of funded debt to total capitalization at December 31, 2018, was 45 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.

On January 1, 2019, the Company's revolving credit agreement and commercial paper program became Montana-Dakota's revolving credit agreement and commercial paper program as a result of the Holding Company Reorganization. The outstanding balance of the revolving credit agreement was also transferred to Montana-Dakota. All of the related terms and covenants of the credit agreements remained the same. For more information on the reorganization, see Note 1.

Cascade Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

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. Cascade's ratio of total debt to total capitalization at December 31, 2018, was 51 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.

Intermountain Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

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. Intermountain's ratio of total debt to total capitalization at December 31, 2018, was 49 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 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 contains 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. Centennial's ratio of total debt to total capitalization at December 31, 2018, was 38 percent. Other covenants include restricted payments, 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 WBI Energy Transmission has a $200.0 million uncommitted note purchase and private shelf agreement with an expiration date of May 16, 2019. WBI Energy Transmission had $140.0 million of notes outstanding at December 31, 2018, which reduced the remaining capacity under this uncommitted private shelf agreement to $60.0 million. 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. WBI Energy Transmission's total debt to total capitalization at December 31, 2018, was

40 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 was as follows:

	Weighted Average Interest Rate at December 31, 2018	2018	2017
		(In thousands)	
Senior Notes due on dates ranging from July 1, 2019 to January 15, 2055	4.57%	$ 1,381,000	$ 1,499,916
Commercial paper supported by revolving credit agreements	3.10%	338,100	88,350
Term Loan Agreements due on dates ranging from October 17, 2019 to September 3, 2032	2.75 %	209,800	—
Credit agreements due on April 24, 2020	4.40%	110,100	57,300
Medium-Term Notes due on dates ranging from September 1, 2020 to March 16, 2029	6.68 %	50,000	50,000
Other notes due on dates ranging from July 1, 2019 to November 30, 2038	5.22%	25,229	24,982
Less unamortized debt issuance costs		5,207	5,694
Less discount		327	1
Total long-term debt		2,108,695	1,714,853
Less current maturities		251,854	148,499
Net long-term debt		$ 1,856,841	$ 1,566,354

Schedule of Debt Maturities Long-term debt maturities, which excludes unamortized debt issuance costs and discount, for the five years and thereafter following December 31, 2018, were as follows:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Long-term debt maturities	$ 251,854	$ 125,912	$ 290,413	$ 147,314	$ 125,714	$ 1,173,022

Note 9 - Asset Retirement Obligations

The Company records obligations related to retirement costs of natural gas distribution mains and lines, natural gas transmission lines, storage facilities, 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 as asset retirement obligations.

A reconciliation of the Company's liability, which is included in other accrued liabilities and deferred credits and other liabilities - other on the Consolidated Balance Sheets, for the years ended December 31 was as follows:

	2018	2017
	(In thousands)	
Balance at beginning of year	$ 341,969	$ 314,970
Liabilities incurred	13,424	15,110
Liabilities acquired	1,002	—
Liabilities settled	(3,699)	(4,981)
Accretion expense*	18,242	16,839
Revisions in estimates	4,615	31
Balance at end of year	$ 375,553	$ 341,969

* Includes $16.8 million and $15.6 million in 2018 and 2017, respectively, related to regulatory assets.

The Company believes that largely all 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. For more information on the Company's regulatory assets and liabilities, see Note 6.

Note 10 - Preferred Stocks

The Company currently has 500,000 shares of preferred stock authorized to be issued with a $100 par value; 1,000,000 shares of preferred stock A authorized to be issued with no par value; and 500,000 shares of preference stock authorized to be issued with no par value. At December 31, 2018, there were no shares outstanding. At December 31, 2017, there were no shares outstanding. In 2016, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. On April 1, 2017, the Company redeemed all outstanding 4.50% Series and 4.70% Series preferred stocks at $105 per share and $102 per share, respectively, for a repurchase price of approximately $15.6 million and $300,000 of redeemable preferred stock classified as long-term debt.

Note 11 - Common Stock

For the years 2018, 2017 and 2016, dividends declared on common stock were $.7950, $.7750 and $.7550 per common share, respectively.

The Stock Purchase Plan provided 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 provides participants the option to invest in the Company's common stock. For the years ended December 31, 2018, 2017 and 2016, the K-Plan purchased shares of common stock on the open market. At December 31, 2018, there were 7.8 million shares of common stock reserved for original issuance under the K-Plan. From January 2016 through December 4, 2016, the Stock Purchase Plan purchased shares of common stock on the open market. On December 5, 2016, the Stock Purchase Plan was terminated and all remaining shares reserved for original issuance under the plan were de-registered.

The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock. The Company has paid quarterly dividends for more than 80 consecutive years with an increase in the payout amount for the last 28 consecutive years. 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 declare or pay distributions if as of the last day of any fiscal quarter, the ratio of Centennial's average consolidated indebtedness as of the last day of such fiscal quarter and each of the preceding three fiscal quarters to Centennial's Consolidated EBITDA does not exceed 3 to 1. Intermountain has regulatory limitations on the amount of dividends it can pay. Based on these limitations, approximately $1.1 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2018. 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 $424 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, 2018. 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 12 - Stock-Based Compensation

The Company has stock-based compensation plans under which it is currently authorized to grant restricted stock and other stock awards. As of December 31, 2018, there were 5.0 million remaining shares available to grant under these plans. The Company either purchases shares on the open market or issues new shares of common stock to satisfy the vesting of stock based awards.

Total stock-based compensation expense (after tax) was $4.6 million, $2.7 million and $3.3 million in 2018, 2017 and 2016, respectively.

As of December 31, 2018, total remaining unrecognized compensation expense related to stock-based compensation was approximately $7.2 million (before income taxes) which will be amortized over a weighted average period of 1.7 years.

Stock awards

Non-employee directors receive shares of common stock in addition to and in lieu of cash payment for directors' fees. Shares of common stock were issued under the non-employee director stock compensation plan or the non-employee director long-term incentive compensation plan. There were 38,605 shares with a fair value of $1.0 million, 40,572 shares with a fair value of $1.1 million and 37,218 shares with a fair value of $1.1 million issued to non-employee directors during the years ended December 31, 2018, 2017 and 2016, respectively.

Restricted stock awards

In February 2018, the Company began granting restricted stock awards under the long-term performance-based incentive plan to certain key employees. The restricted stock awards granted will vest after three years. The grant-date fair value is the market price of the Company's stock on the grant date. At December€31, 2018, the total nonvested shares were 22,838 with a weighted average grant-date fair value of $27.48 per share.

Performance share awards

Since 2003, key employees of the Company have been granted performance share awards each year under the long-term performance-based incentive plan. Entitlement to performance shares is established by either the market condition or the performance metrics and service condition relative to the designated award.

Target grants of performance shares outstanding at December€31, 2018, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2016	2016-2018	255,773
March 2016	2016-2018	2,151
February 2017	2017-2019	164,558
February 2018	2018-2020	246,309

Under the market condition for these performance share awards, participants may earn from zero to 200€percent of the apportioned 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 applicable to the market condition for certain performance shares issued in 2018 , 2017 and 2016 were:

	2018	2017	2016
Weighted average grant-date fair value	$34.55	$24.31	$14.60
Blended volatility range	17.87% , 22.14%	22.70% , 25.56%	29.25% , 32.51%
Risk-free interest rate range	1.86% , 2.46%	.69% , 1.61%	.47% , .92%
Weighted average discounted dividends per share	$2.46	$1.70	$1.56

Under the performance conditions for these performance share awards, participants may earn from zero to 200€percent of the apportioned target grant of shares. The performance conditions are based on the Company's compound annual growth rate in earnings from continuing operations before interest, taxes, depreciation, depletion and amortization and the Company's compound annual growth rate in earnings from continuing operations. The performance shares applicable to these performance conditions have a weighted average grant-date fair value of $27.48 €per share.

There were no performance shares that vested in 2018 . The fair value of the performance shares that vested during the years ended December€31, 2017 and 2016, was $9.6 million and $953,000 , respectively.

A summary of the status of the performance share awards for the year ended December€31, 2018, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	425,534	$ 18.35
Granted	246,309	31.02
Less:		
Forfeited	3,052	14.60
Nonvested at end of period	668,791	$ 23.03

Note 13 - Income Taxes

The components of income before income taxes from continuing operations for each of the years ended December 31 were as follows:

	2018	2017	2016
		(In thousands)	
United States	$ 317,655	$ 350,064	$ 326,252
Foreign	(784)	(37)	(24)
Income before income taxes from continuing operations	$ 316,871	$ 350,027	$ 326,228

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

	2018	2017	2016
		(In thousands)	
Current:			
Federal	$ (15,901)	$ 74,272	$ 81,989
State	3,651	16,192	13,190
Foreign	—	—	2
	(12,250)	90,464	95,181
Deferred:			
Income taxes:			
Federal	50,755	(24,497)	(2,102)
State	7,206	(864)	1,184
Investment tax credit - net	1,774	(62)	(1,131)
	59,735	(25,423)	(2,049)
Total income tax expense	$ 47,485	$ 65,041	$ 93,132

In accordance with the accounting guidance on accounting for income taxes, the tax effects of the change in tax laws or rates are to be recorded in the period of enactment. The TCJA was enacted on December 22, 2017, as discussed in Note 1. Therefore, the reduction in the corporate tax rate from 35 percent to 21 percent required the Company to prepare a one-time revaluation of the Company's deferred tax assets and liabilities in the fourth quarter of 2017, the period of enactment. The deferred taxes were revalued at the new tax rate because deferred taxes should reflect what the Company expects to pay or receive in future periods under the applicable tax rate. As a result of the revaluation, the Company reduced the value of these assets and liabilities and recorded a tax benefit from continuing operations of $39.5 million on the Consolidated Statements of Income for the year ended December 31, 2017. Included in the tax benefit from continuing operations was income tax expense of $7.7 million related to amounts in accumulated other comprehensive loss and $1.0 million related to the Company's assets held for sale.

The Company's regulated operations prepared a one-time revaluation of the Company's regulatory deferred tax assets and liabilities in the fourth quarter of 2017 related to the enactment of the TCJA. The revaluation is being deferred under regulatory accounting as the Company works with the various regulators to plan for amounts expected to be returned to customers, as discussed in Notes 6 and 18. The revaluation of the deferred tax assets and liabilities resulted in a net decrease of $285.5 million in the fourth quarter of 2017. In the third quarter of 2018, the Company reversed a regulatory liability recorded in 2017 based on a FERC final accounting order being issued, which resulted in a $4.2 million tax benefit. These regulatory amounts will largely be refunded over the remaining life of the related assets.

The changes included in the TCJA were broad and complex. The SEC issued rules that allowed for a measurement period of up to one year after the enactment date of the TCJA to finalize the recording of the related tax impacts. The Company has reviewed the impacts of the TCJA and completed its assessment of the transitional impacts during the period ending December 31, 2018, of which there were no such material adjustments.

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

	2018	2017
	(In thousands)	
Deferred tax assets:		
Postretirement	$ 51,930	$ 55,736
Compensation-related	29,885	16,298
Alternative minimum tax credit carryforward	13,404	37,683
Federal renewable energy credit	8,015	19,367
Customer advances	7,734	8,712
Asset retirement obligations	7,083	6,380
Legal and environmental contingencies	6,729	7,363
Other	37,347	35,738
Total deferred tax assets	162,127	187,277
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	476,832	429,577
Postretirement	44,432	43,505
Intangible asset amortization	17,752	16,979
Other	39,712	32,591
Total deferred tax liabilities	578,728	522,652
Valuation allowance	13,484	11,896
Net deferred income tax liability	$ 430,085	$ 347,271

As of December€31, 2018 and 2017 , the Company had various state income tax net operating loss carryforwards of $153.2€million and $130.1€million , respectively, and federal and state income tax credit carryforwards, excluding alternative minimum tax credit carryforwards, of $43.5€million €and$52.5€million , respectively. Included in the state credits are various regulatory investment tax credits of approximately $32.2€million and $28.0€million at December€31, 2018 and 2017 , respectively. The federal income tax credit carryforwards expire in 2037 and 2038 if not utilized and state income tax credit carryforwards are due to expire between 2020 and 2046. Changes in tax regulations or assumptions regarding current and future taxable income could require additional valuation allowances in the future. The alternative minimum tax credit carryforwards are refundable. For information regarding net operating loss carryforwards and valuation allowances related to discontinued operations, see Note€.

The following table reconciles the change in the net deferred income tax liability from December€31, 2017, to December€31, 2018, to deferred income tax expense:

	2018
	(In thousands)
Change in net deferred income tax liability from the preceding table	$ 82,814
Deferred taxes associated with other comprehensive income	(2,679)
Deferred taxes associated with TCJA enactment for regulated activities	(13,776)
Deferred taxes associated with acquisitions	(5,565)
Other	(1,059)
Deferred income tax expense for the period	$ 59,735

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,	2018		2017		2016	
	Amount	%	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	$ 66,543	21.0	$ 122,509	35.0	$ 114,179	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax	12,190	3.8	10,724	3.1	9,027	2.8
Federal renewable energy credit	(11,759)	(3.7)	(13,958)	(4.0)	(13,544)	(4.2)
Tax compliance and uncertain tax positions	(2,725)	(.9)	(643)	(.2)	(3,028)	(.9)
Domestic production deduction	•	•	(6,849)	(2.0)	(6,251)	(1.9)
Excess deferred income tax amortization	(9,319)	(2.9)	(397)	„	(828)	(.2)
TCJA revaluation	(5,947)	(1.9)	(47,242)	(13.5)	„	„
TCJA revaluation related to accumulated other comprehensive loss balance	(42)	•	7,735	2.2	„	„
Other	(1,456)	(.4)	(6,838)	(2.0)	(6,423)	(2.1)
Total income tax expense	$ 47,485	15.0	$ 65,041	18.6	$ 93,132	28.5

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. The Company is no longer subject to U.S. federal or non-U.S. income tax examinations by tax authorities for years ending prior to 2015. With few exceptions, as of December€31, 2018, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2014.

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

	2018	2017	2016
		(In thousands)	
Balance at beginning of year	$ •	$ „	$ „
Additions based on tax positions related to current year	120	„	„
Additions for tax positions of prior years	262	„	„
Balance at end of year	$ 382	$ „	$ „

Included in income tax expense is interest on uncertain tax positions. For the years ended December€31, 2018, 2017 and 2016 , the Company recognized approximately $31,000 , $99,000 and $92,000 , respectively, of interest income in income tax expense. At December€31, 2018, the Company had no accrued receivables for interest. At December 31, 2017 , the Company had accrued receivables of approximately $46,000 , for interest.

Note€14 - Cash Flow Information

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

	2018	2017	2016
		(In thousands)	
Interest, net*	$ 83,009	$ 79,638	$ 87,920
Income taxes paid, net**	$ 16,041	$ 112,137	$ 105,908

* AFUDC - borrowed was $2.3€million, $966,000 and $914,000 for the years ended December€31, 2018 , 2017 and 2016 , respectively.

** Income taxes paid, net of discontinued operations, were $5.5€million, $9.7€million and $1.3€million for the years ended December€31, 2018 , 2017 and 2016 , respectively.

Noncash investing transactions at December€31 were as follows:

	2018	2017	2016
		(In thousands)	
Property, plant and equipment additions in accounts payable	$ 42,355	$ 29,263	$ 22,712
Issuance of common stock in connection with acquisition	$ 18,186	$ „	$ „

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 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 midstream segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment also provides cathodic protection and other energy-related services.

The construction materials and contracting segment operations mine, process and sell construction aggregates (crushed stone, sand and gravel); produce and sell asphalt mix; and supply ready-mixed concrete. This segment focuses on vertical integration of its contracting services with its construction materials to support the aggregate based product lines including aggregate placement, asphalt and concrete paving, and site development and grading. 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. This segment operates in the central, southern and western United States and Alaska and Hawaii.

The construction services segment provides inside and outside specialty contracting services. Its outside services include design, construction and maintenance of overhead and underground electrical distribution and transmission lines, substations, external lighting, traffic signalization, and gas pipelines, as well as utility excavation and the manufacture and distribution of transmission line construction equipment. Its inside services include design, construction and maintenance of electrical and communication wiring and infrastructure, fire suppression systems, and mechanical piping and services. This segment also constructs and maintains renewable energy projects. These specialty contracting services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

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 self-insured layers of the insured Company's general liability, automobile liability, pollution liability and other coverages. Centennial Capital also owns certain real and personal property. The Other category also includes certain general and administrative costs (reflected in operation and maintenance expense) and interest expense which were previously allocated to the refining business and Fidelity and do not meet the criteria for income (loss) from discontinued operations. The Other category also includes Centennial Resources' former investment in Brazil.

Discontinued operations includes the results and supporting activities of Dakota Prairie Refining and Fidelity other than certain general and administrative costs and interest expense as described above. For more information on discontinued operations, see Note 4.

The information below follows the same accounting policies as described in Note 1. Information on the Company's segments as of December€31 and for the years then ended was as follows:

	2018	2017	2016
		(In thousands)	
External operating revenues:			
Regulated operations:			
Electric	$ 335,123	$ 342,805	$ 322,356
Natural gas distribution	823,247	848,388	766,115
Pipeline and midstream	54,857	53,566	52,983
	1,213,227	1,244,759	1,141,454
Nonregulated operations:			
Pipeline and midstream	23,161	19,602	39,602
Construction materials and contracting	1,925,185	1,811,964	1,873,696
Construction services	1,369,772	1,366,317	1,072,663
Other	207	709	1,413
	3,318,325	3,198,592	2,987,374
Total external operating revenues	$ 4,531,552	$ 4,443,351	$ 4,128,828
Intersegment operating revenues:			
Regulated operations:			
Electric	$ •	$ „	$ „
Natural gas distribution	•	„	„
Pipeline and midstream	50,580	48,867	48,794
	50,580	48,867	48,794
Nonregulated operations:			
Pipeline and midstream	325	178	223
Construction materials and contracting	669	565	574
Construction services	1,681	1,285	609
Other	11,052	7,165	7,230
	13,727	9,193	8,636
Intersegment eliminations	(64,307)	(58,060)	(57,430)
Total intersegment operating revenues	$ •	$ „	$ „
Depreciation, depletion and amortization:			
Electric	$ 50,982	$ 47,715	$ 50,220
Natural gas distribution	72,486	69,381	65,426
Pipeline and midstream	17,896	16,788	24,885
Construction materials and contracting	61,158	55,862	58,413
Construction services	15,728	15,739	15,307
Other	1,955	2,001	2,067
Total depreciation, depletion and amortization	$ 220,205	$ 207,486	$ 216,318
Operating income (loss):			
Electric	$ 65,148	$ 79,902	$ 67,929
Natural gas distribution	72,336	84,239	66,166
Pipeline and midstream	36,128	36,004	42,864
Construction materials and contracting	141,426	143,230	178,753
Construction services	86,764	81,292	53,546
Other	(79)	(619)	(349)
Total operating income	$ 401,723	$ 424,048	$ 408,909

	2018	2017	2016
		(In thousands)	
Interest expense:			
Electric	$ 25,860	$ 25,377	$ 24,982
Natural gas distribution	30,768	31,234	30,405
Pipeline and midstream	5,964	4,990	7,903
Construction materials and contracting	17,290	14,778	15,265
Construction services	3,551	3,742	4,059
Other	2,762	3,564	5,854
Intersegment eliminations	(1,581)	(897)	(620)
Total interest expense	$ 84,614	$ 82,788	$ 87,848
Income taxes:			
Electric	$ (6,482)	$ 7,699	$ 1,449
Natural gas distribution	4,075	22,756	9,181
Pipeline and midstream	2,677	12,281	12,408
Construction materials and contracting	28,357	5,405	60,625
Construction services	20,000	25,558	17,748
Other	(1,142)	(1,809)	(2,028)
Intersegment eliminations	•	(6,849)	(6,251)
Total income taxes	$ 47,485	$ 65,041	$ 93,132
Earnings on common stock:			
Regulated operations:			
Electric	$ 47,000	$ 49,366	$ 42,222
Natural gas distribution	37,732	32,225	27,102
Pipeline and midstream	26,905	20,620	22,060
	111,637	102,211	91,384
Nonregulated operations:			
Pipeline and midstream	1,554	(127)	1,375
Construction materials and contracting	92,647	123,398	102,687
Construction services	64,309	53,306	33,945
Other	(761)	(1,422)	(3,231)
	157,749	175,155	134,776
Intersegment eliminations (a)	•	6,849	6,251
Earnings on common stock before income (loss) from discontinued operations	269,386	284,215	232,411
Income (loss) from discontinued operations, net of tax (a)	2,932	(3,783)	(300,354)
Loss from discontinued operations attributable to noncontrolling interest	•	„	(131,691)
Earnings on common stock	$ 272,318	$ 280,432	$ 63,748
Capital expenditures:			
Electric	$ 186,105	$ 109,107	$ 111,134
Natural gas distribution	205,896	146,981	126,272
Pipeline and midstream	70,057	31,054	34,467
Construction materials and contracting	280,396	44,302	37,845
Construction services	25,081	18,630	60,344
Other	1,768	1,850	2,358
Total capital expenditures (b)	$ 769,303	$ 351,924	$ 372,420

		2018		2017		2016
			(In thousands)			
Assets:						
Electric (c)	$	1,613,822	$	1,470,922	$	1,406,694
Natural gas distribution (c)		2,375,871		2,201,081		2,099,296
Pipeline and midstream		616,959		566,295		550,615
Construction materials and contracting		1,508,032		1,238,696		1,220,459
Construction services		604,798		591,382		513,093
Other (d)		266,111		261,419		283,255
Assets held for sale		2,517		4,871		211,055
Total assets	$	6,988,110	$	6,334,666	$	6,284,467
Property, plant and equipment:						
Electric (c)	$	2,148,569	$	1,982,264	$	1,888,613
Natural gas distribution (c)		2,499,093		2,319,845		2,179,413
Pipeline and midstream		764,959		700,284		672,199
Construction materials and contracting		1,768,006		1,560,048		1,549,375
Construction services		188,586		177,265		171,361
Other		28,108		31,123		49,268
Less accumulated depreciation, depletion and amortization		2,818,644		2,691,641		2,578,902
Net property, plant and equipment	$	4,578,677	$	4,079,188	$	3,931,327

(a) Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.
(b) Capital expenditures for 2018, 2017 and 2016 include noncash transactions such as the issuance of the Company's equity securities in connection with acquisitions, capital expenditure-related accounts payable and AFUDC, totaling $33.4 million, $10.5 million and $(15.8) million, respectively.
(c) Includes allocations of common utility property.
(d) 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 16 - Employee Benefit Plans

Pension and other postretirement benefit plans

The Company has noncontributory qualified 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.

Prior to 2013, defined benefit pension plan benefits and accruals for all nonunion and certain union plans were frozen and on June 30, 2015, the remaining union plan was frozen. These employees were eligible to receive additional defined contribution plan benefits. In October 2018, the Company transferred the liability of certain participants in the defined benefit pension plan, who are currently receiving benefits, to an annuity company. The transfer of the benefit payments for these participants reduces the Company's liability and future premiums.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at certain of the Company's businesses. Employees who had 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 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 was 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, 2018 and 2017 , and amounts recognized in the Consolidated Balance Sheets at December€31, 2018 and 2017 , were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	2018	2017
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$ 445,923	$ 436,307	$ 91,206	$ 89,304
Service cost	•	„	1,494	1,508
Interest cost	14,591	16,207	2,899	3,265
Plan participants' contributions	•	„	1,282	1,368
Actuarial (gain) loss	(32,637)	19,119	(10,115)	1,781
Benefits paid	(36,275)	(25,710)	(5,565)	(6,020)
Benefit obligation at end of year	391,602	445,923	81,201	91,206
Change in net plan assets:				
Fair value of plan assets at beginning of year	354,384	333,509	88,739	82,846
Actual gain (loss) on plan assets	(21,138)	45,473	(2,781)	9,612
Employer contribution	10,838	1,112	842	933
Plan participants' contributions	•	„	1,281	1,368
Benefits paid	(36,275)	(25,710)	(5,565)	(6,020)
Fair value of net plan assets at end of year	307,809	354,384	82,516	88,739
Funded status - over (under)	$ (83,793)	$ (91,539)	$ 1,315	$ (2,467)
Amounts recognized in the Consolidated Balance Sheets at December€31:				
Deferred charges and other assets - other	$ •	$ „	$ 20,843	19,114
Other accrued liabilities	•	„	660	612
Deferred credits and other liabilities - other	83,793	91,539	18,868	20,969
Benefit obligation assets (liabilities) - net amount recognized	$ (83,793)	$ (91,539)	$ 1,315	$ (2,467)
Amounts recognized in accumulated other comprehensive (income) loss or regulatory assets (liabilities) consist of:				
Actuarial loss	$ 188,735	$ 186,486	$ 10,316	$ 13,423
Prior service credit	•	„	(10,238)	(11,632)
Total	$ 188,735	$ 186,486	$ 78	$ 1,791

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 table above 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 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.

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:

	2018	2017
	(In thousands)	
Projected benefit obligation	$ 391,602	$ 445,923
Accumulated benefit obligation	$ 391,602	$ 445,923
Fair value of plan assets	$ 307,809	$ 354,384

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

	Pension Benefits			Other Postretirement Benefits		
	2018	2017	2016	2018	2017	2016
			(In thousands)			
Components of net periodic benefit cost (credit):						
Service cost	$ •	$ „	$ „	$ 1,494	$ 1,508	$ 1,647
Interest cost	14,591	16,207	17,218	2,899	3,265	3,688
Expected return on assets	(20,753)	(20,528)	(20,924)	(4,866)	(4,641)	(4,533)
Amortization of prior service credit	•	„	„	(1,394)	(1,371)	(1,371)
Recognized net actuarial loss	7,005	6,355	6,215	640	857	1,491
Net periodic benefit cost (credit), including amount capitalized	843	2,034	2,509	(1,227)	(382)	922
Less amount capitalized	•	310	381	153	(370)	(52)
Net periodic benefit cost (credit)	843	1,724	2,128	(1,380)	(12)	974
Other changes in plan assets and benefit obligations recognized in accumulated comprehensive (income) loss or regulatory assets (liabilities):						
Net (gain) loss	9,254	(5,827)	(3,789)	(2,467)	(3,190)	(3,523)
Amortization of actuarial loss	(7,005)	(6,355)	(6,215)	(640)	(857)	(1,491)
Amortization of prior service credit	•	„	„	1,394	1,371	1,371
Total recognized in accumulated other comprehensive (income) loss or regulatory assets (liabilities)	2,249	(12,182)	(10,004)	(1,713)	(2,676)	(3,643)
Total recognized in net periodic benefit cost (credit), accumulated other comprehensive (income) loss and regulatory assets (liabilities)	$ 3,092	$ (10,458)	$ (7,876)	$ (3,093)	$ (2,688)	$ (2,669)

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost in 2019 is $5.6€million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost (credit) in 2019 are $500,000 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	
	2018	2017	2018	2017
Discount rate	4.03%	3.38%	4.05%	3.41%
Expected return on plan assets	6.75%	6.75%	5.75%	5.75%
Rate of compensation increase	N/A	N/A	3.00%	3.00 %

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

	Pension Benefits		Other Postretirement Benefits	
	2018	2017	2018	2017
Discount rate	3.38%	3.83 %	3.41%	3.86%
Expected return on plan assets	6.75%	6.75 %	5.75%	5.75%
Rate of compensation increase	N/A	N/A	3.00%	3.00 %

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December€31, 2018, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40€percent to 50€percent equity securities and 50€percent to 60€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 25€percent to 30€percent equity securities and 70€percent to 75€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:

	2018	2017
Health care trend rate assumed for next year	7.5% , 8.1%	7.5% , 8.5%
Health care cost trend rate - ultimate	4.5%	4.5%
Year in which ultimate trend rate achieved	2024	2024

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, 2018:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 223	$ (184)
Effect on postretirement benefit obligation	$ 4,296	$ (3,622)

Outside investment managers manage the Company's pension and postretirement assets. 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 fair value 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 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.

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. Government securities are valued based on quoted prices on an active market.

The estimated fair value of the pension plans' Level 2 U.S. Government 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, 2018 and 2017, 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, 2018, 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, 2018
	(In thousands)			
Assets:				
Cash equivalents	$ „	$ 4,930	$ „	$ 4,930
Equity securities:				
U.S. companies	11,038	„	„	11,038
International companies	„	967	„	967
Collective and mutual funds*	145,960	51,600	„	197,560
Corporate bonds	„	73,110	„	73,110
Municipal bonds	„	10,624	„	10,624
U.S. Government securities	479	5,896	„	6,375
Total assets measured at fair value	$ 157,477	$ 147,127	$ „	$ 304,604

* Collective and mutual funds invest approximately 27€percent in common stock of international companies,31€percent in corporate bonds,18€percent in common stock of large-cap U.S. companies,5€percent in cash equivalents and19€percent in other investments.

	Fair Value Measurements at December€31, 2017, 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, 2017
	(In thousands)			
Assets:				
Cash equivalents	$ „	$ 3,814	$ „	$ 3,814
Equity securities:				
U.S. companies	13,345	„	„	13,345
International companies	1,766	„	„	1,766
Collective and mutual funds*	171,822	67,749	„	239,571
Corporate bonds	„	74,956	„	74,956
Municipal bonds	„	8,546	„	8,546
U.S. Government securities	1,038	8,293	„	9,331
Total assets measured at fair value	$ 187,971	$ 163,358	$ „	$ 351,329

* Collective and mutual funds invest approximately 31€percent in common stock of international companies,28€percent in corporate bonds,19€percent in common stock of large-cap U.S. companies,7€percent in cash equivalents,1 percent in U.S. Government securities and14€percent in other investments.

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€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. 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 endedDecember€31, 2018 and 2017 , 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, 2018, 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, 2018
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 3,866	$ —	$ 3,866
Equity securities:				
U.S. companies	1,767	—	—	1,767
International companies	—	2	—	2
Insurance contract*	1	76,880	—	76,881
Total assets measured at fair value	$ 1,768	$ 80,748	$ —	$ 82,516

* The insurance contract invests approximately 51 percent in corporate bonds, 23 percent in common stock of large-cap U.S. companies, 7 percent in U.S. Government securities, 7 percent in common stock of small-cap U.S. companies and 12 percent in other investments.

	Fair Value Measurements at December 31, 2017, 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, 2017
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 4,815	$ —	$ 4,815
Equity securities:				
U.S. companies	2,316	—	—	2,316
International companies	4	—	—	4
Insurance contract*	3	81,601	—	81,604
Total assets measured at fair value	$ 2,323	$ 86,416	$ —	$ 88,739

* The insurance contract invests approximately 38 percent in corporate bonds, 23 percent in common stock of large-cap U.S. companies, 21 percent in U.S. Government securities, 9 percent in mortgage-backed securities and 9 percent in other investments.

The Company expects to contribute approximately $4.0 million to its defined benefit pension plans and approximately $700,000 to its postretirement benefit plans in 2019.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies at December 31, 2018, are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2019	$ 24,026	$ 5,332	$ 117
2020	24,287	5,232	112
2021	24,633	5,201	105
2022	24,929	5,259	98
2023	25,173	5,270	90
2024 - 2028	124,688	25,851	320

Nonqualified benefit plans

In addition to the qualified defined benefit pension plans 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, upon death, to their beneficiaries for a 15-year period. In February 2016, the Company froze the unfunded, nonqualified defined benefit plans to new participants and eliminated benefit increases. Vesting for participants not fully vested was retained.

The projected benefit obligation and accumulated benefit obligation for these plans at December€31 were as follows:

	2018	2017
	(In thousands)	
Projected benefit obligation	$ 93,988	$ 102,484
Accumulated benefit obligation	$ 93,988	$ 102,484

Components of net periodic benefit cost for the Company's nonqualified benefit plans for the years ended December€31 were as follows:

	2018	2017	2016
		(In thousands)	
Components of net periodic benefit cost:			
Service cost	$ 185	$ 289	$ 493
Interest cost	3,157	3,494	3,742
Amortization of prior service cost	•	„	(80)
Recognized net actuarial loss	1,047	883	952
Curtailment gain	•	„	(3,292)
Net periodic benefit cost	$ 4,389	$ 4,666	$ 1,815

Weighted average assumptions used at December€31 were as follows:

	2018	2017
Benefit obligation discount rate	3.86%	3.20%
Benefit obligation rate of compensation increase	N/A	N/A
Net periodic benefit cost discount rate	3.20%	3.56%
Net periodic benefit cost rate of compensation increase	N/A	N/A

The amount of future benefit payments for the unfunded, nonqualified benefit plans at December 31, 2018 , are expected to aggregate as follows:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Nonqualified benefits	$ 7,350	$ 7,766	$ 7,787	$ 7,018	$ 7,213	$ 36,885

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2018 , 2017 and 2016 were $597,000 , $736,000 and $395,000 , respectively.

The amount of investments that the Company anticipates using to satisfy obligations under these plans at December 31 was as follows:

	2018	2017
	(In thousands)	
Investments		
Insurance contract*	$ 73,838	$ 77,388
Life insurance**	37,274	38,568
Other	10,818	6,971
Total investments	$ 121,930	$ 122,927

* For more information on the insurance contract, see Note 7.
** Investments of life insurance are carried on plan participants (payable upon the employee's death).

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees and the costs incurred under these plans were $42.4€million in 2018 , $41.2 million in 2017 and $40.9 million in 2016 .

Multiemployer plans

The Company contributes to a number of MEPPs 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 MEPP 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 MEPPs, 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 2018 and 2017 is for the plan's year-end at December 31, 2017, and December 31, 2016, 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 2018	Pension Protection Act Zone Status 2017	FIP/RP Status Pending/ Implemented	Contributions 2018	Contributions 2017	Contributions 2016	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Alaska Laborers-Employers Retirement Fund	91-6028298-001	Yellow as of 6/30/2018	Yellow as of 6/30/2017	Implemented	$ 732	$ 690	$ 766	No	12/31/2018 *
Construction Industry and Laborers Joint Pension Trust for So Nevada, Plan A	88-0135695-001	Red	Red	Implemented	346	377	523	No	6/30/2019
Edison Pension Plan	93-6061681-001	Green	Green	No	12,111	12,725	6,242	No	6/30/2019
IBEW Local 212 Pension Trust	31-6127280-001	Green as of 4/30/2018	Green as of 4/30/2017	No	1,341	1,312	1,146	No	6/2/2019
IBEW Local 357 Pension Plan A	88-6023284-001	Green	Green	No	3,460	3,286	3,016	No	5/31/2021
IBEW Local 648 Pension Plan	31-6134845-001	Yellow as of 2/28/2018	Red as of 2/28/2017	Implemented	2,175	2,254	773	No	8/29/2021
IBEW Local 82 Pension Plan	31-6127268-001	Green as of 6/30/2018	Green as of 6/30/2017	No	1,569	1,757	2,560	No	12/1/2019
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2018	Green as of 5/31/2017	No	1,247	1,156	1,221	No	9/30/2019
Minnesota Teamsters Construction Division Pension Fund	41-6187751-001	Green as of 11/30/2017	Green as of 11/30/2016	No	740	826	690	No	4/30/2019
National Automatic Sprinkler Industry Pension Fund	52-6054620-001	Red	Red	Implemented	738	718	775	No	3/31/2021-7/31/2024
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	8,468	8,891	6,366	No	1/31/2018-5/31/2022
Pension Trust Fund for Operating Engineers	94-6090764-001	Yellow	Red	Implemented	2,403	2,391	2,069	No	6/15/2019-6/30/2020
Sheet Metal Workers Pension Plan of Southern CA, AZ, and NV	95-6052257-001	Yellow	Yellow	Implemented	1,774	1,016	1,087	No	6/30/2019
Southwest Marine Pension Trust	95-6123404-001	Red	Red	Implemented	81	48	50	No	1/31/2019 *
Other funds					21,537	19,298	17,243		
Total contributions					$ 58,722	$ 56,745	$ 44,527		

* Plan includes contributions required by collective bargaining agreements which have expired, but contain provisions automatically renewing their terms in the absence of a subsequent negotiated 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	2017 and 2016
IBEW Local 82 Pension Plan	2017 and 2016
IBEW Local 124 Pension Trust Fund	2017 and 2016
IBEW Local 212 Pension Trust Fund	2017 and 2016
IBEW Local 357 Pension Plan A	2017 and 2016
IBEW Local 648 Pension Plan	2017 and 2016
Idaho Plumbers and Pipefitters Pension Plan	2017 and 2016
International Union of Operating Engineers Local 701 Pension Trust Fund	2017 and 2016
Minnesota Teamsters Construction Division Pension Fund	2017 and 2016
Pension and Retirement Plan of Plumbers and Pipefitters Local 525	2017 and 2016

On September 24, 2014, Knife River provided notice to the Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming that it was withdrawing from the plan effective October 26, 2014. In the fourth quarter of 2016, Knife River and the plan entered into a settlement agreement whereby the plan administrator assessed Knife Riverƒs final withdrawal liability with quarterly payments of approximately $42,000 until all benefits are satisfied. Knife River discounted the expected future payments. Based on this calculation, Knife River adjusted its liability accrual from $16.4 million to $5.2 million in the fourth quarter of 2016.

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 $53.3 million, $52.2 million and $36.1 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Amounts contributed in 2018, 2017 and 2016 to defined contribution multiemployer plans were $31.1 million, $32.2 million and $23.8 million, respectively.

Note 17 - Jointly Owned Facilities

The consolidated financial statements include the Company's ownership interests in the assets, liabilities and expenses of 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 has an ownership interest of 22.7 percent in Big Stone Station, 25 percent in Coyote Station and 25 percent in Wygen III.

The Company's share of the stations operating expenses was reflected in the appropriate categories of operating expenses (electric fuel and purchased power; 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:

	2018	2017
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 156,534	$ 158,084
Less accumulated depreciation	49,345	51,740
	$ 107,189	$ 106,344
Coyote Station:		
Utility plant in service	$ 155,236	$ 155,287
Less accumulated depreciation	105,565	103,897
	$ 49,671	$ 51,390
Wygen III:		
Utility plant in service	$ 65,382	$ 65,065
Less accumulated depreciation	9,174	7,652
	$ 56,208	$ 57,413

Note 18 - Regulatory Matters

The Company regularly reviews the need for electric and natural gas rate changes in each of the jurisdictions in which service is provided. The Company files for rate adjustments to seek recovery of operating costs and capital investments, as well as reasonable returns as allowed by regulators. The Company's most recent cases by jurisdiction are discussed in the following paragraphs. The jurisdictions in which the Company provides service have requested the Company furnish plans for the effect of the reduced corporate tax rate due to the enactment of the TCJA which may impact the Company's rates. The following paragraphs include additional details and statuses of each open request.

MNPUC

On December 29, 2017, the MNPUC issued a notice of investigation related to tax changes with the enactment of the TCJA. On January 19, 2018, the MNPUC issued a notice of request for information, commission planning meeting and subsequent comment period. Pursuant to the notice, Great Plains provided preliminary impacts of the TCJA on January 30, 2018. On March 2, 2018, Great Plains submitted its initial filing addressing the impacts of the TCJA advocating existing rates are reasonable and a reduction in rates is not warranted. On August 9, 2018, the MNPUC ruled that Great Plains reduce rates to reflect TCJA impacts and to also provide a one-time refund that captures the TCJA impacts from January 1, 2018 through the implementation date of new rates. On December 5, 2018, the MNPUC issued an order requiring Great Plains reduce its rates by $400,000 on an annual basis and provide a one-time refund of approximately $400,000, as previously mentioned, within 90 days after the rates are implemented through credits to customers' bills. The required compliance filing was submitted to the MNPUC on January 4, 2019.

MTPSC

On December 27, 2017, the MTPSC requested Montana-Dakota identify a plan for the impacts of the TCJA and to file a proposal for the impacts on the electric segment by March 31, 2018. On April 2, 2018, Montana-Dakota submitted its plan requesting the MTPSC recognize the identified need for additional rate relief and to consider the effects of the TCJA in a general electric rate case to be submitted by September 30, 2018. Montana-Dakota submitted the general electric rate case on September 28, 2018, as discussed below. On November 30, 2018, Montana-Dakota and interveners of the case submitted a stipulation and settlement agreement reflecting a one-time refund of approximately $1.5 million to account for all TCJA related impacts from January 1, 2018 through the date new rates are effective in the rate case noted below. A hearing was held on December 4, 2018, and the MTPSC issued an order accepting the stipulation and settlement agreement on December 21, 2018, requiring a one-time bill credit to occur in April 2019.

On September 28, 2018, Montana-Dakota filed an application with the MTPSC for an electric rate increase of approximately $11.9 million annually or approximately 18.9 percent above current rates. The requested increase is primarily to recover investments in facilities to enhance safety and reliability and the depreciation and taxes associated with the increase in investment. The increase was offset by tax savings related to the TCJA. This matter is pending before the MTPSC.

NDPSC

On July 21, 2017, Montana-Dakota filed an application with the NDPSC for a natural gas rate increase of approximately $5.9 million annually or approximately 5.4 percent above current rates. The requested increase is primarily to recover the increased investment in distribution facilities to enhance system safety and reliability and the depreciation and taxes associated with the increase in investment. Montana-Dakota also introduced a SSIP and the proposed adjustment mechanism required to fund the SSIP. Montana-Dakota requested an interim increase of approximately $4.6 million or approximately 4.2 percent, subject to refund. On September 6, 2017, the NDPSC approved the request for interim rates effective with service rendered on or after September 19, 2017. On February 14, 2018, Montana-Dakota filed a revised interim increase request of approximately $2.7 million, subject to refund, incorporating the estimated impacts of the TCJA reduction in the federal corporate income tax rate. On March 1, 2018, the updated interim rates were implemented. The impact of the TCJA was submitted as part of a rebuttal testimony identifying a reduction of the adjusted revenue requirement to approximately $3.6 million. On July 19, 2018, a settlement was filed reflecting a revised annual revenue increase of approximately $2.5 million or approximately 2.3 percent. The proposed adjustment mechanism to fund the SSIP was not included in the settlement and will be decided on separately by the NDPSC. On September 26, 2018, the NDPSC issued an order approving the settlement as filed but did not approve the SSIP recovery mechanism. On October 5, 2018, Montana-Dakota submitted a compliance filing, which included a plan for the one-time refund to be available March 1, 2019, for the interim amount to be refunded to customers. The NDPSC approved the compliance rates and were effective with service rendered on and after December 1, 2018.

On January 10, 2018, the NDPSC issued a general order initiating the investigation into the effects of the TCJA. The order required regulatory deferral accounting on the impacts of the TCJA and for companies to file comments and the expected impacts. On February 15, 2018, Montana-Dakota filed a summary of the primary impacts of the TCJA on the electric and natural gas utilities. On March 9, 2018, Montana-Dakota submitted a request to decrease its electric rates by $7.2 million or 3.9 percent annually. On August 10, 2018, a settlement agreement was filed requesting a decrease in rates of approximately $8.4 million. On September 26, 2018, the NDPSC issued an order approving the settlement along with requiring an additional adjustment to the rates to return 100 percent of the tax-effective 2018 excess deferred income taxes. On October 10, 2018, Montana-Dakota submitted a compliance filing, which included a refund plan for the interim amount to be refunded to customers. On November 20, 2018, the NDPSC approved the compliance rates which were effective with service rendered on and after December 1, 2018. The NDPSC also approved a one-time refund of approximately $7.9 million to be credited to customers' bills by March 15, 2019, based on 4.7 percent of the revenues collected between January 1, 2018 through November 30, 2018.

On October 19, 2018, Great Plains and the NDPSC advocacy staff filed a settlement agreement to resolve all outstanding issues in the NDPSC's investigation into the TCJA and a revenue neutral tariff filing submitted by Great Plains. The settlement agreement provides for miscellaneous tariff changes and a reduction in annual revenues of $168,000. On January 9, 2019, the NDPSC issued an order approving the settlement agreement and a refund requirement for the period from January 1, 2018 through the month preceding the effective date of the rate change. On January 23, 2019, the NDPSC approved the compliance rates to be effective February 1, 2019, along with the refund plan that provides for approximately $200,000 in refunds to be credited to customers' bills by April 15, 2019.

OPUC

On December 29, 2017, Cascade filed a request with the OPUC to use deferral accounting for the 2018 net benefits associated with the implementation of the TCJA. The deferral request was renewed on December 28, 2018. This matter is pending before the OPUC.

On May 31, 2018, Cascade filed a general rate case with the OPUC requesting an overall increase of approximately $2.3 million or approximately 3.5 percent on an annual basis, which incorporates the impact of the TCJA. On January 22, 2019, Cascade filed a stipulation with the OPUC for an annual increase in revenues of $1.7 million with a $500,000 reduction for excess deferred income taxes, for a net increase of $1.2 million. This matter is pending before the OPUC.

SDPUC

On December 29, 2017, the SDPUC issued an order initiating the investigation into the effects of the TCJA. The order required Montana-Dakota to provide comments by February 1, 2018, regarding the general effects of the TCJA on the cost of service in South Dakota and possible mechanisms for adjusting rates. The order also stated that all rates impacted by the federal income tax shall be adjusted effective January 1, 2018, subject to refund. On May 4, 2018 and June 2, 2018, Montana-Dakota submitted detailed plans to address the TCJA impacts on the natural gas and electric utilities, respectively, to the SDPUC staff. On September 28, 2018, a settlement agreement was submitted to the SDPUC reflecting a proposal to refund approximately $600,000 to electric customers and approximately $1.3 million to natural gas customers. These refunds reflect the impact of the TCJA on 2018. On October 23, 2018, an order was issued by the SDPUC approving the settlement agreement with the refunds being credited to customers' bills beginning on February 15, 2019. On December 3, 2018, Montana-Dakota submitted proposed rate changes to reflect 2018 pro forma results and the TCJA impacts. On December 28, 2018, the SDPUC approved an annual decrease in revenues of approximately $300,000 for the natural gas operations and approximately $100,000 for the electric operations. The decrease in revenues was effective January 1, 2019.

WUTC

On June 1, 2018, Cascade filed its annual pipeline cost recovery mechanism requesting an increase in annual revenue of $2.3 million or approximately 1.1 percent. On October 11, 2018, Cascade filed a revised increase in annual revenue of $2.1 million or approximately 1.0 percent. The increase was effective November 1, 2018.

WYPSC

On December 29, 2017, the WYPSC issued a general order requiring regulatory deferral accounting on the impacts of the TCJA. A technical conference was held on February 6, 2018, to discuss the implications of the TCJA. On March 23, 2018, the WYPSC issued an order requiring all public utilities to submit an initial assessment of the overall effects on the TCJA on their rates by March 30, 2018. On March 30, 2018, Montana-Dakota submitted its initial assessment indicating a rate reduction for its electric rates in the amount of approximately $1.1 million annually or approximately 4.2 percent. Revised electric rates reflecting this reduction were submitted to the WYPSC on June 13, 2018. Montana-Dakota reported its natural gas earnings do not support a decrease in rates and requested the WYPSC allow the impacts of the TCJA be addressed in a natural gas rate case to be submitted by June 1, 2019. Both matters are pending before the WYPSC.

FERC

Montana-Dakota and certain MISO Transmission Owners with projected rates submitted a filing to the FERC on February 1, 2018, requesting the FERC to waive certain provisions of the MISO tariff in order for Montana-Dakota and certain MISO Transmission Owners with projected rates to revise their rates to reflect the reduction in the corporate tax rate. Under the MISO tariff, rates are to be changed only on an annual basis with any changes reflected in subsequent true-ups. On March 15, 2018, the FERC approved the waiver request and new rates reflecting the effects of the TCJA were implemented by MISO on March 1, 2018. MISO also retroactively re-billed the January and February 2018 services to reflect the new rates. On September 4, 2018, Montana-Dakota filed an update to its transmission formula rate under the MISO tariff for the multivalue project for $12.5 million, which is effective January 1, 2019.

On July 18, 2018, the FERC issued a final rule on Rate Changes Relating to Federal Income Tax Rate reductions resulting from the TCJA which requires natural gas pipeline companies to make a one-time informational filing to evaluate the impact of the lower corporate income tax rate and also select one of four options presented by the FERC to address the impact. In accordance with WBI Energy Transmission's offer of settlement and stipulation and agreement with the FERC dated June 4, 2014, the Company is to make a filing with new proposed rates to be effective no later than May 1, 2019. On October 31, 2018, the Company filed a rate case with the FERC. Due to the timing of the rate case filing, the Company was exempt from the one-time informational filing required by the FERC's final rule. On November 30, 2018, the FERC issued an order accepting and suspending tariff records, subject to refund, and establishing hearing procedures. The FERC order accepted the Company's rate case filing and suspended the associated tariff records to be effective May 1, 2019, subject to refund and the outcome of a hearing.

Note 19 - Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries, which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. 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. Accruals are based on the best information available, but in certain situations management is unable to estimate an amount or range of a reasonably possible loss including, but not limited to when: (1) the damages are unsubstantiated or indeterminate, (2) the proceedings are in the early stages, (3) numerous parties are involved, or (4) the matter involves novel or unsettled legal theories.

The Company has accrued liabilities of $30.4 million and $35.4 million, which have not been discounted, including liabilities held for sale, for contingencies, including litigation, production taxes, royalty claims and environmental matters at December 31, 2018 and 2017, respectively. This includes amounts that have been accrued for matters discussed in Environmental matters within this note. The Company will continue to monitor each matter and adjust accruals as might be warranted based on new information and further developments. Management believes that the outcomes with respect to probable and reasonably possible losses in excess of the amounts accrued, net of insurance recoveries, while uncertain, either cannot be estimated or will not have a material effect upon the Company's financial position, results of operations or cash flows. Unless otherwise required by GAAP, legal costs are expensed as they are incurred.

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 $100 million. On January 6, 2017, Region 10 of the EPA issued an ROD with its selected remedy for cleanup of the in-river portion of the site. Implementation of the remedy is expected to take up to 13 years with a present value cost estimate of approximately $1 billion. Corrective action will not be taken until remedial design/remedial action plans are approved by the EPA. 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 matter.

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 accruals related to these claims are reflected in regulatory assets. For more information, see Note 6.

The first claim is for contamination at a site in Eugene, Oregon, which was received in 1995. The Oregon DEQ released an ROD in January 2015 that selected a remediation alternative for the site as recommended in an earlier staff report. The total estimated cost for the selected remediation, including long-term maintenance, is approximately $3.5 million of which $400,000 has been incurred. Cascade and other PRPs will share in the cleanup costs with Cascade expecting to pay approximately 50 percent of the remediation and maintenance costs. Cascade has an accrual balance of $1.5 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 orders reauthorizing the deferred accounting for the 12-month periods starting November 30, 2013, December 1, 2014, December 1, 2015, December 1, 2016, December 1, 2017 and December 1, 2018.

The second claim is for contamination at the Bremerton Gasworks Superfund 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. In April 2010, the Washington DOE 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. Current estimates for the cost to complete the remedial investigation and feasibility study are approximately $7.6 million of which $3.1 million has been incurred. Cascade has accrued $4.5 million for the remedial investigation and feasibility study, as well as $6.4 million for remediation of this site; however, the accrual for remediation costs will be reviewed and adjusted, if necessary, after completion of the remedial investigation and feasibility study. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs incurred in relation to the environmental remediation of this site. 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. Other PRPs reached an agreed order and work plan with the Washington DOE for completion of a remedial investigation and feasibility study for the site. A feasibility study prepared in March 2018 identifies five cleanup action alternatives for the site with estimated costs ranging from $8.0 million to $20.4 million with a selected preferred alternative having an estimated total cost of $9.3 million. 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 recorded an accrual for this site for an amount that is not material.

Cascade has received notices from and entered into agreement with certain of its insurance carriers that they will participate in defense of Cascade for certain of the 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 intends to seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

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, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Operating leases	$ 37,740	$ 26,255	$ 17,868	$ 11,647	$ 7,278	$ 49,098

Rent expense was $74.6 million, $73.7 million and $65.0 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Purchase commitments

The Company has entered into various commitments, largely construction, natural gas and coal supply, purchased power, natural gas transportation and storage, and service, shipping and construction materials supply contracts, some of which are subject to variability in volume and price. The commitment terms vary in length, up to 42 years. The commitments under these contracts as of December 31, 2018, were:

	2019	2020	2021	2022	2023	Thereafter
			(In thousands)			
Purchase commitments	$ 418,106	$ 215,069	$ 169,716	$ 115,884	$ 84,268	$ 622,383

These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2018, 2017 and 2016, were $548.0 million, $516.1 million and $539.3 million, respectively.

Guarantees

In June 2016, WBI Energy sold all of the outstanding membership interests in Dakota Prairie Refining. In connection with the sale, Centennial agreed to continue to guarantee certain debt obligations of Dakota Prairie Refining which were expected to mature in 2023. Tesoro agreed to indemnify Centennial for any losses and litigation expenses arising from the guarantee. Continuation of the guarantee was required as a condition to the sale of Dakota Prairie Refining. On October 17, 2018, Centennial was released from this guarantee of certain debt obligations of Dakota Prairie Refining.

In 2009, multiple sale agreements were signed to sell the Company's ownership interests in the Brazilian Transmission Lines. In connection with the sale, Centennial agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who were 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.

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, insurance deductibles and loss limits, and certain other guarantees. At December 31, 2018, the fixed maximum amounts guaranteed under these agreements aggregated $196.3 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate to $85.3 million in 2019; $104.0 million in 2020; $500,000 in 2021; $500,000 in 2022; $500,000 in 2023; $1.5 million thereafter; and $4.0 million, which has no scheduled maturity date. There were no amounts outstanding under the above guarantees at December 31, 2018. 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, 2018, the fixed maximum amounts guaranteed under these letters of credit aggregated $30.0 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these letters of credit aggregate to $6.7 million in 2019 and $23.3 million in 2020. There were no amounts outstanding under the above letters of credit at December 31, 2018. In the event of default under these letter of credit obligations, the subsidiary guaranteeing the letter of credit would be obligated for reimbursement of payments made under the letter of credit.

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 or MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company were reflected on the Consolidated Balance Sheet at December 31, 2018.

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. At December 31, 2018, approximately $697.9 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.

Fuel Contract Coyote Station entered into a coal supply agreement with Coyote Creek that provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station for the period May 2016 through December 2040. Coal purchased under the coal supply agreement is reflected in inventories on the Company's Consolidated Balance Sheets and is recovered from customers as a component of electric fuel and purchased power.

The 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, 2018, the Company's exposure to loss as a result of the Company's involvement with the VIE, based on the Company's ownership percentage was $38.5 million.

Note 20 - Subsequent Event

On February 19, 2019, the Company announced that it intends to retire three aging coal-fired electric generation units within the next three years due to the fact that the plants are no longer expected to be cost competitive. The retirements are expected to be in late 2020 in Sidney, Montana, and in late 2021 in Mandan, North Dakota. A plan is in place to maintain staff until the plant retirements. These dates may be impacted by the Company's coal supplier's pending bankruptcy proceeding. In addition, the Company announced that it intends to construct a new simple-cycle natural gas combustion turbine peaking unit at the existing plant site in Mandan, North Dakota.

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2018 and 2017 :

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2018				
Operating revenues	$ 976,293	$ 1,064,597	$ 1,280,787	$ 1,209,875
Operating expenses	906,917	990,605	1,140,783	1,091,524
Operating income	69,376	73,992	140,004	118,351
Income from continuing operations	41,960	44,075	107,369	75,982
Income (loss) from discontinued operations, net of tax	477	(273)	(118)	2,846
Net income	42,437	43,802	107,251	78,828
Earnings per common share - basic:				
Earnings before discontinued operations	.22	.22	.55	.39
Discontinued operations, net of tax	•	•	•	.01
Earnings per common share - basic	.22	.22	.55	.40
Earnings per common share - diluted:				
Earnings before discontinued operations	.22	.22	.55	.39
Discontinued operations, net of tax	•	•	•	.01
Earnings per common share - diluted	.22	.22	.55	.40
Weighted average common shares outstanding:				
Basic	195,304	195,524	196,018	196,023
Diluted	195,982	196,169	196,265	196,385
2017				
Operating revenues	$ 937,925	$ 1,067,639	$ 1,272,548	$ 1,165,239
Operating expenses	872,139	988,979	1,117,228	1,040,957
Operating income	65,786	78,660	155,320	124,282
Income from continuing operations	35,638	44,405	89,549	115,394
Income (loss) from discontinued operations, net of tax	1,687	(3,190)	(2,198)	(82)
Net income	37,325	41,215	87,351	115,312
Earnings per common share - basic:				
Earnings before discontinued operations	.18	.22	.46	.59
Discontinued operations, net of tax	.01	(.01)	(.01)	„
Earnings per common share - basic	.19	.21	.45	.59
Earnings per common share - diluted:				
Earnings before discontinued operations	.18	.22	.46	.59
Discontinued operations, net of tax	.01	(.01)	(.01)	„
Earnings per common share - diluted	.19	.21	.45	.59
Weighted average common shares outstanding:				
Basic	195,304	195,304	195,304	195,304
Diluted	196,023	195,973	195,783	195,617

Notes:
… Fourth quarter 2017 reflects an income tax benefit of $39.5 million related to the TCJA. For more information, see Note 13 .

Certain operations of the Company 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.

Definitions

The following abbreviations and acronyms used in Notes to Consolidated Financial Statements are defined below:

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7€percent ownership)
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines in Brazil
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
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's Consolidated EBITDA	Centennial's consolidated net income from continuing operations plus the related interest expense, taxes, depreciation, depletion, amortization of intangibles and any non-cash charge relating to asset impairment for the preceding 12-month period
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
Company	MDU Resources Group, Inc. (formerly known as MDUR Newco), which, as the context requires, refers to the previous MDU Resources Group, Inc. prior to January 1, 2019, and the new holding company of the same name after January 1, 2019
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 built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company previously owned by WBI Energy and Calumet (previously included in the Company's refining segment)
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
EIN	Employer Identification Number
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings (previously referred to as the Company's exploration and production segment)
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company prior to the closing of the Holding Company Reorganization and a public utility division of Montana-Dakota as of January 1, 2019
Holding Company Reorganization	The internal holding company reorganization completed on January 1, 2019, pursuant to the agreement and plan of merger, dated as of December 31, 2018, by and among Montana-Dakota, the Company and MDUR Newco Sub, which resulted in the Company becoming a holding company and owning all of the outstanding capital stock of Montana-Dakota.
IBEW	International Brotherhood of Electrical Workers
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
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
LWG	Lower Willamette Group
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
MDUR Newco	MDUR Newco, Inc., a public holding company created by implementing the Holding Company Reorganization, now known as the Company
MDUR Newco Sub	MDUR Newco Sub, Inc., a direct, wholly owned subsidiary of MDUR Newco, which was merged with and into Montana‚Dakota in the Holding Company Reorganization
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.

MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co. (formerly known as MDU Resources Group, Inc.), a public utility division of the Company prior to the closing of the Holding Company Reorganization and a direct wholly owned subsidiary of MDU Energy Capital as of January 1, 2019
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
Oil	Includes crude oil and condensate
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PRP	Potentially Responsible Party
ROD	Record of Decision
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
SSIP	System Safety and Integrity Program
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan which was terminated effective December€5, 2016
TCJA	Tax Cuts and Jobs Act
Tesoro	Tesoro Refining & Marketing Company LLC
VIE	Variable interest entity
Washington DOE	Washington State Department of Ecology
WBI Energy	WBI Energy, Inc., a direct wholly owned subsidiary of WBI Holdings
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
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

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 three months ended December€31, 2018, 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

Information required by this item will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item€11. Executive Compensation

Information required by this item will be included in the Company's Proxy Statement, which 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, 2018, 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)	691,629 (2)	$ „ (3)	4,357,330 (4)(5)
Equity compensation plans not approved by stockholders	N/A	N/A	N/A
Total	691,629	$ „	4,357,330

(1) Consists of the Non-Employee Director Long-Term Incentive Compensation Plan and the Long-Term Performance-Based Incentive Plan.
(2) Consists of performance shares and restricted stock awards.
(3) No weighted average exercise price is shown for the performance shares or restricted stock awards because such awards have no exercise price.
(4) This amount includes 4,041,479 €shares available for future issuance under the Long-Term Performance-Based Incentive Plan in connection with grants of restricted stock, performance units, performance shares or other equity-based awards.
(5) This amount includes 315,851 shares available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan.

The remaining information required by this item will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item€13. Certain Relationships and Related Transactions, and Director Independence

Information required by this item will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item€14. Principal Accounting Fees and Services

Information required by this item will be included in the Company's Proxy Statement, which is incorporated herein by reference.

Item€15. Exhibits, 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.

2. Financial Statement Schedules

The following financial statement schedules are included in Part IV of this report.

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

Years ended December€31,	2018	2017	2016
		(In thousands)	
Operating revenues	$ 628,331	$ 623,693	$ 561,266
Operating expenses	540,125	520,069	469,853
Operating income	88,206	103,624	91,413
Other income	1,504	4,876	2,282
Interest expense	32,761	31,997	31,519
Income before income taxes	56,949	76,503	62,176
Income taxes	(4,259)	13,800	6,355
Equity in earnings of subsidiaries from continuing operations	208,177	222,283	177,275
Net income from continuing operations	269,385	284,986	233,096
Equity in earnings (loss) of subsidiaries from discontinued operations attributable to the Company	2,933	(3,783)	(168,663)
Loss on redemption of preferred stocks	•	600	„
Dividends declared on preferred stocks	•	171	685
Earnings on common stock	$ 272,318	$ 280,432	$ 63,748
Comprehensive income	$ 279,269	$ 279,602	$ 65,848

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,	2018	2017
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 2,271	$ 843
Receivables, net	92,724	83,453
Accounts receivable from subsidiaries	36,015	34,029
Inventories	13,293	13,864
Prepayments and other current assets	14,488	34,400
Total current assets	158,791	166,589
Investments	76,202	76,779
Investment in subsidiaries	1,790,886	1,704,908
Property, plant and equipment	2,846,715	2,631,161
Less accumulated depreciation, depletion and amortization	836,735	797,130
Net property, plant and equipment	2,009,980	1,834,031
Deferred charges and other assets:		
Goodwill	4,812	4,812
Other	180,473	175,599
Total deferred charges and other assets	185,285	180,411
Total assets	$ 4,221,144	$ 3,962,718
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	$ 200,711	$ 100,011
Accounts payable	50,051	47,000
Accounts payable to subsidiaries	12,438	7,234
Taxes payable	24,704	13,717
Dividends payable	39,695	38,573
Accrued compensation	14,346	20,017
Other accrued liabilities	54,099	36,881
Total current liabilities	396,044	263,433
Long-term debt	586,012	612,493
Deferred credits and other liabilities:		
Deferred income taxes	165,122	147,847
Other	507,191	509,902
Total deferred credits and other liabilities	672,313	657,749
Commitments and contingencies		
Stockholders' equity:		
Common stock		
Authorized - 500,000,000 shares, $1.00 par value		
Issued - 196,564,907 shares in 2018 and 195,843,297 shares in 2017	196,565	195,843
Other paid-in capital	1,248,576	1,233,412
Retained earnings	1,163,602	1,040,748
Accumulated other comprehensive loss	(38,342)	(37,334)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total stockholders' equity	2,566,775	2,429,043
Total liabilities and stockholders' equity	$ 4,221,144	$ 3,962,718

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,		2018		2017		2016
				(In thousands)		
Net cash provided by operating activities	$	294,379	$	284,075	$	238,125
Investing activities:						
Capital expenditures		(242,692)		(146,370)		(159,570)
Net proceeds from sale or disposition of property and other		5,032		(5,665)		3,784
Investments in and advances to subsidiaries		(40,000)		(40,000)		(5,000)
Advances from subsidiaries		70,000		40,000		15,000
Investments		(528)		(468)		(129)
Net cash used in investing activities		(208,188)		(152,503)		(145,915)
Financing activities:						
Issuance of long-term debt		199,422		70,080		106,420
Repayment of long-term debt		(125,961)		(37,569)		(50,010)
Payments of stock issuance costs		(10)		„		„
Dividends paid		(154,573)		(150,727)		(147,156)
Redemption of preferred stock		•		(15,600)		„
Repurchase of common stock		(1,920)		(564)		„
Tax withholding on stock-based compensation		(1,721)		(508)		(226)
Net cash used in financing activities		(84,763)		(134,888)		(90,972)
Increase (decrease) in cash and cash equivalents		1,428		(3,316)		1,238
Cash and cash equivalents - beginning of year		843		4,159		2,921
Cash and cash equivalents - end of year	$	2,271	$	843	$	4,159

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 as of December 31, 2018, prior to the Holding Company Reorganization. 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 from subsidiaries is reported as equity in earnings of subsidiaries on the Condensed Statements of Income. The consolidated financial statements of MDU Resources Group, Inc. reflect certain businesses as discontinued operations. These statements should be read in conjunction with the consolidated financial statements and notes thereto of MDU Resources Group, Inc.

Earnings per common share Please refer to the Consolidated Statements of Income of the registrant for earnings per common share. In addition, see Item 8 - Note€1 for information on the computation of earnings per common share.

Note€2 - Debt At December€31, 2018, the Company had long-term debt maturities, excluding unamortized debt issuance costs, of $200.7€million in 2019, $700,000 in 2020, $700,000 in 2021, $700,000 in 2022, $49.2 million in 2023 and $536.7€million scheduled to mature in years after 2023.

For more information on debt, see Item 8 - Note 8.

Note€3 - Dividends The Company depends on earnings and dividends from its subsidiaries to pay dividends on common stock Cash dividends paid to the Company by subsidiaries were $115.9€million, $116.1€million and $115.8€million for the years ended December€31, 2018, 2017 and 2016, respectively.

MDU RESOURCES GROUP, INC.

Schedule€II - Consolidated Valuation and Qualifying Accounts

For the years ended December€31, 2018 , 2017 and 2016

Description	Balance at Beginning of Year	Additions: Charged to Costs and Expenses	Additions: Other *	Deductions **	Balance at End of Year
		(In thousands)			
Allowance for doubtful accounts:					
2018	$ 8,069	$ 7,532	$ 1,121	$ 7,872	$ 8,850
2017	10,479	7,024	989	10,423	8,069
2016	9,835	8,302	851	8,509	10,479

* 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.

Item€16. Form 10-K Summary

None.

3. Exhibits

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference: Form	Period Ended	Exhibit	Filing Date	File Number
2(a)	Membership Interest Purchase Agreement, dated as of June€24, 2016, between WBI Energy, Inc. and Tesoro Refining & Marketing Company LLC		8-K/A		2.1	7/21/16	1-03480
2(b)	Purchase and Sale Agreement, dated as of June 9, 2016, by and among Calumet North Dakota, LLC, WBI Energy, Inc., and as applicable, MDU Resources Group, Inc., Centennial Energy Holdings, Inc., and Calumet Specialty Products Partners, L.P.		8-K/A		2.2	7/21/16	1-03480
2(c)	Amendment No.€1 to Purchase and Sale Agreement, dated as of June€9, 2016, by and among Calumet North Dakota, LLC, WBI Energy, Inc., and as applicable, MDU Resources Group, Inc., Centennial Energy Holdings, Inc., and Calumet Specialty Products Partners, L.P.		8-K/A		2.3	7/21/16	1-03480
2(d)	Agreement and Plan of Merger, dated December 31, 2018, by and among MDU Resources Group, Inc., MDUR Newco, Inc. MDU Newco Sub, Inc.		8-K		2(a)	1/2/19	1-03480
3(a)	Certificate of Merger, dated December 31, 2018		8-K		3(a)	1/2/19	1-03480
3(b)	Amended and Restated Certificate of Incorporation of MDU Resources Group, Inc.		8-K		3(a)	1/2/19	1-03480
3(c)	Amended and Restated Bylaws of MDU Resources Group, Inc.		8-K		3.1	2/15/19	1-03480
4(a)	Indenture, dated as of December 15, 2003, between MDU Resources Group, Inc. and The Bank of New York, as trustee		S-8		4(f)	1/21/04	333-112035
4(b)	First Supplemental Indenture, dated as of November 17, 2009, between MDU Resources Group, Inc. and the Bank of New York Mellon, as trustee		10-K	12/31/09	4(c)	2/17/10	1-03480
4(c)	Centennial Energy Holdings, Inc. Amended and Restated Master Shelf Agreement, effective as of April 29, 2005, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America and certain investors described therein		10-Q	6/30/05	4(a)	8/3/05	1-03480

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
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		10-Q	6/30/06	4(a)	8/4/06	1-03480
4(e)	Letter Amendment No. 2 to Amended and Restated Master Shelf Agreement, dated December 19, 2007, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment		10-K	12/31/15	4(e)	2/19/16	1-03480
4(f)	Letter Amendment No. 3 to Amended and Restated Master Shelf Agreement, dated December 18, 2015, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment		10-K	12/31/15	4(f)	2/19/16	1-03480
4(g)	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		10-K	12/31/11	4(e)	2/24/12	1-03480
4(h)	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		10-Q	9/30/12	4	11/7/12	1-03480
4(i)	Second Amendment to Credit Agreement, dated May 8, 2014 among MDU Resources Group Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent		10-Q	6/30/14	4(a)	8/8/14	1-03480
4(j)	Third Amended and Restated Credit Agreement, dated May 8, 2014, among Centennial Energy Holdings Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto		10-Q	6/30/14	4(b)	8/8/14	1-03480
4(k)	Fourth Amended and Restated Credit Agreement, dated as of September 23, 2016, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto		10-Q	9/30/16	4	11/7/16	1-03480
4(l)	First Amendment to the Fourth Amended and Restated Credit Agreement, dated as of October 26, 2018, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto	X					1-03480
4(m)	MDU Energy Capital, LLC Master Shelf Agreement, dated as of August 9, 2007, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America and the holders of the notes thereunder		8-K		4	8/16/07	1-03480
4(n)	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		10-Q	9/30/08	4(b)	11/5/08	1-03480
4(o)	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		8-K		4	8/12/92	1-07196
4(p)	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		10-Q	6/30/93	4		1-07196
4(q)	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		8-K		4.1	1/26/05	1-07196

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
4(r)	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		8-K		4.1	3/8/07	1-07196
4(s)	MDU Resources Group, Inc. Credit Agreement, dated June 8, 2018, among MDU Resources Group, Inc, Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent		10-Q	6/30/18	4(a)	8/3/18	1-03480
+10(a)	MDU Resources Group, Inc. Supplemental Income Security Plan, as amended and restated May 10, 2017		10-Q	6/30/17	10(d)	8/4/17	1-03480
+10(b)	MDU Resource Group, Inc. Director Compensation Policy, as amended November 15, 2018	X					1-03480
+10(c)	Deferred Compensation Plan for Directors, as amended May€15, 2008		10-Q	6/30/08	10(a)	8/7/08	1-03480
+10(d)	Non-Employee Director Stock Compensation Plan, as amended May 12, 2011		10-Q	6/30/11	10(a)	8/5/11	1-03480
+10(e)	MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan, as amended May 17, 2012		10-Q	6/30/12	10(a)	8/7/12	1-03480
+10(f)	MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan, as amended February 11, 2016		10-K	12/31/15	10(f)	2/19/16	1-03480
+10(g)	MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended May 10, 2017, and Rules and Regulations, as amended May 9, 2017		10-Q	6/30/17	10(b)	8/4/17	1-03480
+10(h)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 10, 2016		8-K		10.3	2/18/16	1-03480
+10(i)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 16, 2017		8-K		10.1	2/21/17	1-03480
+10(j)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 14, 2018		8-K		10.1	2/21/18	1-03480
+10(k)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 14, 2019	X					1-03480
+10(l)	Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 10, 2016		8-K		10.2	2/18/16	1-03480
+10(m)	Restricted Stock Unit Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 14, 2018		8-K		10.3	2/21/18	1-03480
+10(n)	Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, dated May€15, 2014		8-K		10.1	5/15/14	1-03480
+10(o)	Form of Amendment No. 1 to Indemnification Agreement, dated May 15, 2014		8-K		10.2	5/15/14	1-03480
+10(p)	MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of October 10, 2017		10-Q	9/30/17	10(b)	11/3/17	1-03480
+10(q)	MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as amended May 10, 2017		10-Q	6/30/17	10(c)	8/4/17	1-03480
+10(r)	MDU Resources Group, Inc. 401(k) Retirement Plan, as restated January 1, 2017		10-Q	3/31/17	10(a)	5/8/17	1-03480
+10(s)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 31, 2017		10-Q	3/31/17	10(b)	5/8/17	1-03480

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
+10(t)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated April 10, 2017		10-Q	6/30/17	10(e)	8/4/17	1-03480
+10(u)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 30, 2017		10-Q	9/30/17	10(a)	11/3/17	1-03480
+10(v)	Employment Letter for Jeffrey S. Thiede, dated May 16, 2013		10-K	12/31/13	10(ab)	2/21/14	1-03480
+10(w)	Jason L. Vollmer Offer Letter, dated March 7, 2016		8-K		10.2	3/8/16	1-03480
+10(x)	Jason L. Vollmer Offer Letter, dated September 20, 2017		8-K		10.1	9/21/17	1-03480
21	Subsidiaries of MDU Resources Group, Inc.	X					
23	Consent of Independent Registered Public Accounting Firm	X					
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X					
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X					
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	X					
95	Mine Safety Disclosures	X					
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document						
101.SCH	XBRL Taxonomy Extension Schema Document						
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document						
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document						
101.LAB	XBRL Taxonomy Extension Label Linkbase Document						
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document						

+€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 22, 2019 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 22, 2019
/s/ Jason L. Vollmer Jason L. Vollmer (Vice President, Chief Financial Officer and Treasurer)	Chief Financial Officer	February 22, 2019
/s/ Stephanie A. Barth Stephanie A. Barth (Vice President, Chief Accounting Officer and Controller)	Chief Accounting Officer	February 22, 2019
/s/ Harry J. Pearce Harry J. Pearce (Chair of the Board)	Director	February 22, 2019
/s/ Thomas Everist Thomas Everist	Director	February 22, 2019
/s/ Karen B. Fagg Karen B. Fagg	Director	February 22, 2019
/s/ Mark A. Hellerstein Mark A. Hellerstein	Director	February 22, 2019
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 22, 2019
/s/ William E. McCracken William E. McCracken	Director	February 22, 2019
/s/ Patricia L. Moss Patricia L. Moss	Director	February 22, 2019
/s/ Edward A. Ryan Edward A. Ryan	Director	February 22, 2019
/s/ David M. Sparby David M. Sparby	Director	February 22, 2019
/s/ John K. Wilson John K. Wilson	Director	February 22, 2019

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 22, 2019

Fellow Stockholders:

I invite you to join me, our Board of Directors and members of our senior management team for our annual meeting at 1 p.m. CDT May 7, 2019, at 909 Airport Road in Bismarck, North Dakota.

At the meeting, stockholders will vote on the items outlined in this proxy statement, including election of our Board of Directors, approval of our independent auditors, and approval of the amended certificates of incorporation for MDU Resources Group and Montana-Dakota Utilities.

Our director slate up for election includes three candidates who have not previously been on the ballot: Edward A. Ryan, David M. Sparby and Chenxi Wang. Edward and David were appointed to the board during 2018. Chenxi has been put forward as a candidate by our Nominating and Governance Committee because of her expertise in technology and cybersecurity. These three new candidates will help ensure a smooth leadership transition as Bart Holaday did not stand for re-election in 2018 and Harry Pearce and Bill McCracken will not stand for re-election this year. Our corporate bylaws state that directors are not eligible for election to the board after their 76th birthday. We deeply appreciate the diligent and faithful service that Harry, Bart and Bill have provided to MDU Resources stockholders. Harry, especially, has served you well in his 22 years as a director, including five years as independent lead director and the past 14 years as chair of the board.

Also before stockholders for a vote are resolutions to amend the certificates of incorporation for MDU Resources and Montana-Dakota Utilities. These amendments follow the reorganization of our corporate structure at the start of 2019. The reorganization was undertaken to further delineate the separation between our utility companies and our other businesses. Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. were originally structured as divisions of MDU Resources, as required by the Public Utility Holding Company Act of 1935. The Energy Policy Act of 2005 repealed the PUHCA and allowed us to restructure these companies as a subsidiary. Montana-Dakota Utilities is now a subsidiary of MDU Resources and Great Plains Natural Gas is a division of Montana-Dakota Utilities. This reorganization simplifies our corporate structure and provides greater flexibility in our financing options.

In addition to the business items to be conducted at the annual meeting, I will provide an overview of our strong 2018 financial results and the acquisitions and other growth projects we accomplished. We started 2019 with strong momentum, and I will tell you more about the record backlog of work we have at our construction operations and the additional growth projects we expect to complete this year

I look forward to seeing you May 7. Details on how to receive an admission ticket to attend our annual meeting are included in the Notice of Annual Meeting of Stockholders as well as on page 67 of this Proxy Statement.

If you cannot attend the annual stockholder meeting, your vote is still important to us. I ask that you please promptly follow the instructions on your notice or proxy card to vote.

We appreciate your continued investment in MDU Resources and remain committed to providing the long-term value you expect.

Sincerely

David L. Goodin
President and Chief Executive Officer

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 MAY 7, 2019

March 22, 2019

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 58504, on Tuesday, May 7, 2019, at 11:00 a.m., Central Daylight Saving Time, for the following purposes:

Items of Business	1. Election of directors; 2. Advisory vote to approve the compensation paid to the company's named executive officers; 3. Ratification of the appointment of Deloitte & Touche LLP as the company's independent registered public accounting firm for 2019; 4. Approval of an Amendment to Montana-Dakota Utilities Co.'s Restated Certificate of Incorporation; 5. Approval of Amendments to Update and Modernize the Company's Amended and Restated Certificate of Incorporation; and 6. Transaction of any other business that may properly come before the meeting or any adjournment(s) thereof.
Record Date	The board of directors has set the close of business on March 8, 2019, 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.
Meeting Attendance	All stockholders as of the record date of March 8, 2019, are cordially invited and urged to attend the annual meeting. You must request an admission ticket to attend. If you are a stockholder of record and plan to attend the meeting, please contact MDU Resources Group, Inc. by email at CorporateSecretary@mduresources.com or by telephone at 701-530-1010 to request an admission ticket. A ticket will be sent to you by mail. If your shares are held beneficially in the name of a bank, broker, or other holder of record, and you plan to attend the annual meeting, you will need to submit a written request for an admission ticket by mail to: Investor Relations, MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506 or by email at CorporateSecretary@mduresources.com. The request must include proof of stock ownership as of March 8, 2019, such as a bank or brokerage firm account statement or a legal proxy from the bank, broker, or other holder of record confirming ownership. A ticket will be sent to you by mail. Requests for admission tickets must be received no later than May 1, 2019. You must present your admission ticket and state-issued photo identification, such as a driver's license, to gain admittance to the meeting.
Proxy Materials	Notice of Availability of Proxy Materials will be sent on or about March 22, 2019. The Notice contains basic information about the annual meeting and instructions on how to view our proxy materials and vote electronically on the Internet. Stockholders who do not receive the Notice will receive a paper copy of our proxy materials, which will be sent on or about March 28, 2019.

By order of the Board of Directors,

Daniel S. Kuntz
Secretary

Important Notice Regarding the Availability of Proxy Materials for the Stockholder Meeting to be Held on May 7, 2019.
The 2019 Notice of Annual Meeting and Proxy Statement and 2018 Annual Report to Stockholders are available at www.mdu.com/proxymaterials.

TABLE OF CONTENTS

PROXY STATEMENT SUMMARY

To assist you in reviewing the company's 2018 performance and voting your shares, we call your attention to key elements of our 2019 Proxy Statement. The following is only a summary and does not contain all the information you should consider. You should read the entire Proxy Statement carefully before voting. For more information about these topics, please review the full Proxy Statement and our 2018 Annual Report to Stockholders.

Meeting Information

Time and Date:
11:00 a.m. Central Daylight Saving Time Tuesday, May 7, 2019
Place:
MDU Service Center 909 Airport Road Bismarck, ND 58504

Summary of Stockholder Voting Matters

Voting Matters	Board Vote Recommendation	See Page
Item 1. Election of Directors	FOR Each Nominee	7
Item 2. Advisory Vote to Approve the Compensation Paid to the Company's Named Executive Officers	FOR	29
Item 3. Ratification of the Appointment of Deloitte & Touche LLP as the Company's Independent Registered Public Accounting Firm for 2019	FOR	57
Item 4. Approval of an Amendment to Montana-Dakota Utilities Co.'s Restated Certificate of Incorporation	FOR	60
Item 5. Approval of Amendments to Update and Modernize the Company's Amended and Restated Certificate of Incorporation	FOR	61

Corporate Governance Highlights

MDU Resources Group, Inc. is committed to strong corporate governance practices. The following highlights our corporate governance practices and policies. See the sections entitled "Corporate Governance" and "Executive Compensation" for more information on the following:

- ✓ Annual Election of All Directors
- ✓ Majority Voting for Directors
- ✓ Succession Planning and Implementation Process
- ✓ Separate Board Chair and CEO
- ✓ Executive Sessions of Independent Directors at Every Regularly Scheduled Board Meeting
- ✓ Annual Board and Committee Self-Evaluations
- ✓ Risk Oversight by Full Board and Committees
- ✓ All Directors are Independent Other Than Our CEO
- ✓ "Proxy Access" Allowing Stockholders to Nominate Directors in Accordance With the Terms of Our Bylaws
- ✓ Standing Committees Consist Entirely of Independent Directors
- ✓ Active Investor Outreach Program
- ✓ Stock Ownership Requirements for Directors and Executive Officers
- ✓ Anti-Hedging and Anti-Pledging Policies for Directors and Executive Officers
- ✓ No Related Party Transactions by Our Directors or Executive Officers
- ✓ Compensation Recovery/Clawback Policy
- ✓ Annual Advisory Approval on Executive Compensation
- ✓ Mandatory Retirement for Directors at Age 76
- ✓ Directors May Not Serve on More Than Three Public Boards Including the Company's Board

Business Performance Highlights

Our overall performance in 2018 was consistent with our long-term strategy as we focused on growing our regulated energy delivery and construction materials and services business segments. In addition to our 2018 financial performance highlighted on the next page:

- Our electric distribution segment completed the purchase of the Thunder Spirit Wind Farm expansion in southwest North Dakota. The purchase boosts the production capacity of the wind farm from 107.5 megawatts to 155 megawatts of renewable energy. This increases the segment's renewable generation capacity from 22% to 27% of its total generation capacity. Construction continued in 2018 on the 345-kilovolt transmission line project from Ellendale, North Dakota, to Big Stone City, South Dakota, and was completed in February 2019.
- Our construction materials and contracting segment completed the following four acquisitions during 2018:
  - Sweetman Const. Co. located in Sioux Falls, South Dakota;
  - Teevin & Fischer Quarry, LLC located in northern Oregon;
  - Tri-City Paving, Inc. located in Little Falls, Minnesota; and
  - Molalla Redi-Mix and Rock Products, Inc. located south of Portland, Oregon.
- The pipeline and midstream segment in 2018 had record transportation volumes for the second consecutive year. The segment expanded Line Section 27 of its natural gas transportation system in northwestern North Dakota. The project involved construction of approximately 13 miles of pipeline and associated facilities. The expansion provides Line Section 27 with capacity to transport over 600,000 dekatherms per day. The segment also completed construction of its 38-mile Valley Expansion Project transmission line in eastern North Dakota and western Minnesota. The segment is proceeding with construction planning on its Demicks Lake Project in McKenzie County, North Dakota, and Line Section 22 Project near Billings, Montana. Both of these projects are expected to be completed in 2019.
- On January 1, 2019, we completed a holding company reorganization to provide additional financing flexibility and further separation between the company's utility and other business segments. As a result of the reorganization, all of the company's utility operations will be conducted through wholly-owned subsidiaries.

Including our accomplishments in 2018, we are optimistic about the company's future financial performance. The chart below shows our progress over the last five years.

* MDU Resources Group, Inc. reported 2017 earnings from continuing operations of $1.45 per share which included a non-recurring benefit of 20 cents per share attributable to the federal Tax Cuts and Jobs Act that was signed into law on December 22, 2017.

2018 Financial Performance Highlights

- Strong year-over-year performance from continuing operations at both our regulated energy segments and our construction materials and services segments resulted in earnings per share from continuing operations of $1.38 per share compared to $1.45 per share in 2017, which included a benefit of 20 cents per share attributable to the federal Tax Cuts and Jobs Act. Including discontinued operations, 2018 earnings were $272.3 million, or $1.39 per share, compared to $280.4 million, or $1.43 cents per share, in 2017.
- Return of stockholder value through dividends:
  - Increased dividend for 28th straight year; and
  - Paid uninterrupted dividend for 81 straight years.
- Maintained BBB+ stable credit rating from Standard & Poor's and Fitch rating agencies.[1]

28 Years of Consecutive Dividend Increases	Dividends Paid $739 Million Over the Last 5 Years	81 Years of Uninterrupted Dividend Payments

Compensation Highlights

The company's executive compensation is focused on paying for performance. Our compensation program is structured to strongly align compensation with the company's financial performance as a substantial portion of our executive compensation is based upon performance incentive awards.

- Over 75% of our chief executive officer's target compensation and over 58% of our other named executive officers' target compensation is performance based.
- 100% of our chief executive officer's annual and long-term incentive compensation is tied to performance against pre-established, specific, measurable financial goals.
- We require our executive officers to own a significant amount of company stock based upon a multiple of their base salary.

2018 Named Executive Officer Target Pay Mix

*Includes time-vesting restricted stock units for certain named executive officers.

[1] A securities rating is not a recommendation to buy, sell, or hold securities, and it may be revised or withdrawn at any time by the rating agency.

Key Features of Our Executive Compensation Program

What We Do
☑ Pay for Performance - Annual and long-term award incentives tied to performance measures set by the compensation committee comprise the largest portion of executive compensation.
☑ Independent Compensation Committee - All members of the compensation committee meet the independence standards under the New York Stock Exchange listing standards and the Securities and Exchange Commission rules.
☑ Independent Compensation Consultant - The compensation committee retains an independent compensation consultant to evaluate executive compensation plans and practices.
☑ Competitive Compensation - Executive compensation reflects executive performance, experience, relative value compared to other positions within the company, relationship to competitive market value compensation, business segment economic environment, and the actual performance of the overall company and the business segments.
☑ Annual Cash Incentive - Payment of annual cash incentive awards are based on business segment and overall company performance against pre-established financial measures.
☑ Long-Term Equity Incentive - The long-term performance-based equity incentive in the form of performance shares represents approximately 56% of our CEO's and approximately 37% of our other named executive officers' 2018 target compensation, which may only be earned based on achievement of established performance measures at the end of a three-year period.
☑ Annual Compensation Risk Analysis - We regularly analyze the risks related to our compensation programs and conduct an annual broad risk assessment.
☑ Stock Ownership and Retention Requirements - Executive officers are required to own, within five years of appointment or promotion, company common stock equal to a multiple of their base salary. The executive officers also must retain at least 50% of the net after-tax shares of stock vested through the long-term incentive plan for at least two years or until termination of employment.
☑ Clawback Policy - If the company's audited financial statements are restated, the compensation committee may, or shall if required, demand repayment of some or all incentives paid to our executive officers within the last three years.

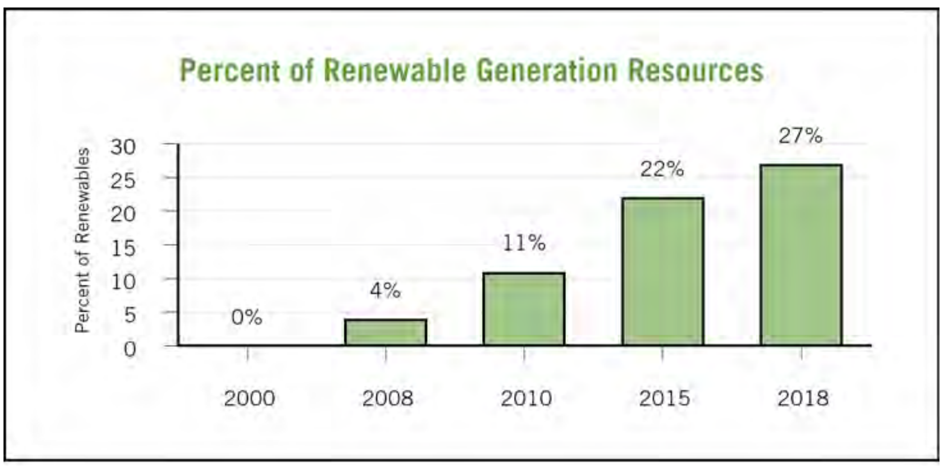
What We Do Not Do
☒ Stock Options - The company does not use stock options as a form of incentive compensation.
☒ Employment Agreements - Executives do not have employment agreements entitling them to specific payments upon termination or a change of control of the company.
☒ Perquisites - Executives do not receive perquisites that materially differ from those available to employees in general.
☒ Hedge Stock - Executives and directors are not allowed to hedge company securities.
☒ Pledge Stock - Executives and directors are not allowed to pledge company securities in margin accounts or as collateral for loans.
☒ No Dividends or Dividend Equivalents on Unvested Shares - We do not provide for payment of dividends or dividend equivalents on unvested share awards.

Corporate Responsibility, Environmental, and Sustainability

MDU Resources Group, Inc. is Building a Strong America® by providing essential products and services to our customers with a long-term view toward sustainable operations. To ensure we can continue to provide these products and services in the communities where we do business, we recognize that we must preserve the trust our communities place in us to be a good corporate citizen. We remain committed to pursuing responsible corporate governance and environmental practices and to maintaining the health and safety of the public and our employees. Learn about our sustainability efforts in our Sustainability Report, which is available at www.mdu.com/sustainability. To better serve our investors and other stakeholders, in 2019 we will begin reporting environmental, social, governance, and sustainability (ESG/ sustainability) metrics relevant and important to our operations in frameworks that will provide our stakeholders more uniform and transparent data and information, allowing for comparison with our peers and other companies operating in our industries. For our electric and natural gas distribution segments, as well as our pipeline and midstream segment, we intend to report ESG/sustainability metrics using the reporting templates developed by the Edison Electric Institute and the American Gas Association. For our other business segments, we intend to report ESG/sustainability information under the framework developed by the Sustainability Accounting Standards Board (SASB) for our applicable industries. The use of the metrics developed by these organizations provides for ESG/sustainability reporting tailored to our industries.

These are some highlights of our recent efforts regarding sustainability:

- As our renewable generation resource capacity has increased, the carbon dioxide (CO_2) emission intensity of our electric generation resource fleet has been reduced by approximately 24% since 2003. We expect it to continue to decline in future years.
- Renewable resources comprised approximately 27% of our electric generation resource nameplate capacity at December 31, 2018.



- Approximately 21% of the electricity delivered to our customers from company-owned generation in 2018 was from renewable resources.
- We invested approximately $133 million in environmental emission control equipment and other environmental improvements at our coal-fired electric generation plants since 2013. The investments have resulted in substantial reductions in mercury, sulfur dioxide, nitrogen oxide, and filterable particulate emissions from our coal-fired electric generation resources.
- Montana-Dakota Utilities Co. produces renewable natural gas (RNG) from the Billings Regional Landfill in Montana. The project came online at the end of 2010 and has produced approximately 1.1 million dekatherm of RNG through year-end 2018. The RNG is supplied to the vehicle fuel market generating renewable identification numbers (RINS) and low carbon fuel standard (LCFS) credits in California and Oregon. In calendar year 2018, the Billings Landfill Plant produced approximately 1.86 million RINs and 3,250 LCFS credits.
- Our utility companies received high scores in customer satisfaction. Cascade Natural Gas Corporation ranked first, Intermountain Gas Company second, and Montana-Dakota Utilities Co. third among West Region mid-sized natural gas utilities in the 2018 J.D. Power Gas Utility Residential Customer Satisfaction Survey.
- We were recognized on the Thomson Reuters 2017 Top 25 Global Multiline Utilities list. The list recognizes companies that have demonstrated a commitment to energy leadership in these areas: financial, management and investor confidence, risk and resilience, legal compliance, innovation, people and social sustainability, environmental impact, and reputation.

- Knife River Corporation produces and places warm-mix asphalt in applications where warm-mix asphalt is allowed. Warm-mix asphalt is produced at cooler temperatures than traditional hot-mix asphalt methods, which reduces the amount of fuel needed in the production process and thereby reduces emissions and fumes.
- Knife River Corporation continued its practice of recycling and reusing building materials. This conserves natural resources, uses less energy, alleviates waste disposal problems in local landfills, and ultimately costs less for the consumer.
- Our subsidiary, Bombard Renewable Energy, was ranked No. 13 on Solar Power World's 2018 Top 500 Solar Contractors List. The list ranks companies according to their influence in the U.S. solar industry based on how many kilowatts of solar generation they installed in 2017.
- The MDU Resources Foundation awarded grants of $1.68 million to educational and nonprofit institutions in 2018. Since its incorporation in 1983, the foundation has contributed more than $34 million to worthwhile causes in categories of education, civic and community activities, culture and arts, environmental stewardship, and health and human services.
- We encourage and support community volunteerism by our employees. The MDU Resources Foundation contributes a $500 grant to an eligible nonprofit organization after an employee volunteers a minimum of 25 hours to the organization during non-company hours during a calendar year. In 2018, the foundation granted $40,500 under this program, matching over 4,850 employee volunteer hours.

21% of 2018 Electricity Generated From Renewable Resources	Grants Awarded $1.68 Million in 2018	24% Reduction in CO_2 Intensity Since 2003

BOARD OF DIRECTORS

ITEM 1. ELECTION OF DIRECTORS

The board currently consists of eleven directors, all of whom, except Harry J. Pearce and William E. McCracken, are standing for election to the board at the 2019 Annual Meeting of Stockholders to hold office until the 2020 annual meeting and until their successors are duly elected and qualified. Mr. Pearce and Mr. McCracken will be retiring following the annual meeting in accordance with our retirement age limits. In February 2019, the board of directors determined to reduce the number of directors to ten effective with the 2019 annual meeting and has nominated Chenxi Wang as a new director nominee to stand for election to the board at the annual meeting.

The board has affirmatively determined that all the director nominees, other than David L. Goodin, our president and chief executive officer, are independent in accordance with New York Stock Exchange (NYSE) rules, our governance guidelines, and our bylaws.

Our bylaws provide for a majority voting standard for the election of directors. See "Additional Information - Majority Voting" below for further detail.

Each of the director nominees has consented to be named in this proxy statement and to serve as a director, if elected. We do not know of any reason why any nominee would be unable or unwilling to serve as a director, if elected. If, however, a nominee becomes unable to serve or will not serve, proxies may be voted for the election of such other person nominated by the board as a substitute or the board may further reduce the number of directors.

Information about each director nominee's share ownership is presented below under "Security Ownership."

The shares represented by the proxies received will be voted for the election of each of the ten nominees named below, unless you indicate in the proxy that your vote should be cast against any or all the director nominees or that you abstain from voting. Each nominee elected as a director will continue in office until his or her successor has been duly elected and qualified or until the earliest of his or her resignation, retirement, or death.

The ten nominees for election to the board at the 2019 annual meeting, all proposed by the board, are listed below with brief biographies.

The board of directors recommends that the stockholders vote FOR the election of each nominee.

Director Nominees

Thomas Everist Age 69	Independent Director Since 1995 Compensation Committee	Other Current Public Boards: --Raven Industries, Inc.

Mr. Everist has more than 44 years of business experience in the construction materials and aggregate mining industry. He has business leadership and management experience serving as president and chair of his companies for over 31 years. Mr. Everist also has experience serving as a director and chair of another public company, which enhances his contributions to our board.

Career Highlights

- President and chair of The Everist Company, Sioux Falls, South Dakota, an investment and land development company, since April 2002. Prior to January 2017, The Everist Company was engaged in aggregate, concrete, and asphalt production.
- Managing member of South Maryland Creek Ranch, LLC, a land development company; president of SMCR, Inc., an investment company, since June 2006; and managing member of MCR Builders, LLC, which provides residential building services to South Maryland Creek Ranch, LLC, since November 2014.
- Director and chair of the board of Everist Health, Inc., Ann Arbor, Michigan, which provides solutions for personalized medicines, since 2002, and chief executive officer from August 2012 to December 2012.
- President and chair of L.G. Everist, Inc., Sioux Falls, South Dakota, an aggregate production company, from 1987 to April 2002.

Other Leadership Experience

- Director of publicly traded Raven Industries, Inc., Sioux Falls, South Dakota, a general manufacturer of electronics, flow controls, and engineered films, since 1996, and chair from April 2009 to May 2017.
- Director of Showplace Wood Products, Inc., Sioux Falls, South Dakota, a custom cabinets manufacturer, since January 2000.
- Director of Bell, Inc., Sioux Falls, South Dakota, a manufacturer of folding cartons and packages, since April 2011.
- 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.
- Member of the South Dakota Investment Council, the state agency responsible for prudently investing state funds, from July 2001 to June 2006.

Education

- Bachelor’s degree in mechanical engineering and a master’s degree in construction management from Stanford University.

Karen B. Fagg
Age 65

Independent Director Since 2005
Compensation Committee
Nominating and Governance Committee

Ms. Fagg brings experience to our board in construction and engineering, energy, and the responsible development of natural resources, which are all important aspects of our business. In addition to her industry experience, Ms. Fagg has over 20 years of business leadership and management experience, including over eight years as president, chief executive officer, and chair of her own company, as well as knowledge and experience acquired through her service on a number of Montana state and community boards.

Career Highlights

- Vice president of DOWL LLC, dba DOWL HKM, an engineering and design firm, from April 2008 until her retirement in December 2011.
- President of HKM Engineering, Inc., Billings, Montana, an engineering and physical science services firm, from April 1995 to June 2000, and chair, chief executive officer, and majority owner from June 2000 through March 2008. HKM Engineering, Inc. merged with DOWL LLC on April 1, 2008.
- Employed with MSE, Inc., Butte, Montana, an energy research and development company, from 1976 through 1988, and vice president of operations and corporate development director from 1993 to April 1995.
- 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, for a four-year term from 1989 through 1992.

Other Leadership Experience

- Director of the Billings Catholic Schools Board from December 2011 through December 2018, including a term as chair; and director of St. Vincent's Healthcare Board from October 2003 to October 2009 and from January 2016 to present, including a term as chair.
- Former member of several state and community boards, including the First Interstate BancSystem Foundation, from June 2013 to 2016; the Montana Justice Foundation, whose mission is to achieve equal access to justice for all Montanans through effective funding and leadership, from 2013 into 2015; Board of Trustees of Carroll College from 2005 through 2010; Montana Board of Investments, the state agency responsible for prudently investing state funds, from 2002 through 2006; Montana State University's Advanced Technology Park from 2001 to 2005; and Deaconess Billings Clinic Health System from 1994 to 2002.

Education

- Bachelor's degree in mathematics from Carroll College in Helena, Montana.

David L. Goodin
Age 57

Director Since 2013
President and Chief Executive Officer

As chief executive officer of MDU Resources Group, Inc., Mr. Goodin is the only officer of the company that serves on our board. With over 35 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. In addition, Mr. Goodin provides the board with valuable insight into management's views and perspectives, as well as the day-to-day operations of the company.

Career Highlights

- President and chief executive officer and a director of the company since January 4, 2013.
- Prior to January 4, 2013, served as chief executive officer and president of Intermountain Gas Company, Cascade Natural Gas Corporation, Montana-Dakota Utilities Co., and Great Plains Natural Gas Co.
- Began his career in 1983 at Montana-Dakota Utilities Co. as a division electrical engineer and served in positions of increasing responsibility until 2007 when he was named president of Cascade Natural Gas Corporation; positions included division electric superintendent, electric systems manager, vice president-operations, and executive vice president-operations and acquisitions.

Other Leadership Experience

- Member of the U.S. Bancorp Western North Dakota Advisory Board since January 2013.
- Director of Sanford Bismarck, an integrated health system dedicated to the work of health and healing, and Sanford Living Center, since January 2011.
- Former 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 Energy Council.

Education and Professional

- Bachelor of science degree in electrical and electronics engineering from North Dakota State University and a master's degree in business administration from the University of North Dakota.
- The Advanced Management Program at Harvard School of Business.
- Registered professional engineer in North Dakota.

Mark A. Hellerstein
Age 66

Independent Director Since 2013
Audit Committee

Mr. Hellerstein has extensive business experience in the energy industry as a result of his 17 years of senior management experience and service as board chair of St. Mary Land & Exploration Company (now SM Energy Company). 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.

Career Highlights

- 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; president from 1992 until June 2006; 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 chair from 2002 until May 2009.
- Several positions prior to joining St. Mary in 1991, including 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 and owns 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.

Other Leadership Experience

- Director of Transocean Inc., a leading provider of offshore drilling services for oil and gas wells, from December 2006 to November 2007.
- Director of the Denver Children's Advocacy Center, whose mission is to provide a continuum of care for traumatized children and their families, from August 2006 until December 2011, including chair for the last three years.

Education and Professional

- Bachelor's degree in accounting from the University of Colorado.
- Certified public accountant, on inactive status.

Dennis W. Johnson
Age 69

Independent Director Since 2001
Audit Committee
Nominating and Governance Committee

Vice Chair of the Board

Mr. Johnson brings to our board over 44 years of experience in business management, manufacturing, and finance, holding positions as chair, president, and chief executive officer of TMI Corporation for 37 years, as well as through his prior service as a director of the Federal Reserve Bank of Minneapolis. 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.

Career Highlights

- Vice chair of the board of the company effective February 15, 2018.
- Chair, president, and chief executive officer of TMI Corporation, and chair and chief executive officer of TMI Transport Corporation, manufacturers of casework and architectural woodwork in Dickinson, North Dakota; employed since 1974 and serving as president or chief executive officer since 1982.

Other Leadership Experience

- Member of the Bank of North Dakota Advisory Board of Directors since August 2017.
- President of the Dickinson City Commission from July 2000 through October 2015.
- Director of the Federal Reserve Bank of Minneapolis from 1993 through 1998.
- Served on numerous industry, state, and community boards, including the North Dakota Workforce Development Council (chair); the Decorative Laminate Products Association; the North Dakota Technology Corporation; and the business advisory council of the Steffes Corporation, a metal manufacturing and engineering firm.
- 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.

Education

- Bachelor of science in electrical and electronics engineering and master of science in industrial engineering from North Dakota State University.

Patricia L. Moss
Age 65

Independent Director Since 2003
Compensation Committee
Nominating and Governance Committee

Other Current Public Boards:
--First Interstate BancSystem, Inc.
--Aquila Group of Funds

Ms. Moss has business experience and knowledge of the Pacific Northwest economy and state, local, and regional issues where a significant portion of our operations are located. Ms. Moss provides our board with experience in finance and banking, as well as experience in business development through her work at Cascade Bancorp and Bank of the Cascades, and on the Oregon Investment Fund Advisory Council, the Oregon Business Council, and the Oregon Growth Board. Ms. Moss also has experience as a certified senior professional in human resources.

Career Highlights

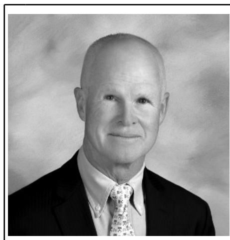
- President and chief executive officer of Cascade Bancorp, a financial holding company, Bend, Oregon, from 1998 to January 3, 2012; chief executive officer of Cascade Bancorp's principal subsidiary, Bank of the Cascades, from 1998 to January 3, 2012, serving also as president from 1998 to 2003; and chief operating officer, chief financial officer and secretary of Cascade Bancorp from 1987 to 1998.

Other Leadership Experience

- Member of the Oregon Investment Council, which oversees the investment and allocation of all state of Oregon trust funds, since December 2018.
- Director of First Interstate BancSystem, Inc., since May 30, 2017.
- Director of Cascade Bancorp and Bank of the Cascades from 1993, and vice chair from January 3, 2012 until May 30, 2017 when Cascade Bancorp merged into First Interstate BancSystem, Inc., and became First Interstate Bank.
- Chair of the Bank of the Cascades Foundation Inc. from 2014 to July 31, 2018; co-chair of the Oregon Growth Board, a state board created to improve access to capital and create private-public partnerships, from May 2012 through December 2018; and a member of the Board of Trustees for the Aquila Group of Funds, whose core business is mutual fund management and provision of investment strategies to fund shareholders, from January 2002 to May 2005 (one fund) and from June 2015 to present (currently three funds).
- Former director of the Oregon Investment Fund Advisory Council, a state-sponsored program to encourage the growth of small businesses in Oregon; the Oregon Business Council, with a mission to mobilize business leaders to contribute to Oregon's quality of life and economic prosperity; the North Pacific Group, Inc., a wholesale distributor of building materials, industrial, and hardwood products; Clear Choice Health Plans Inc., a multi-state insurance company; and City of Bend's Juniper Ridge management advisory board.

Education

- Bachelor of science in business administration from Linfield College in Oregon and master's studies at Portland State University.
- Commercial banking school certification at the ABA Commercial Banking School at the University of Oklahoma.



Edward A. Ryan
Age 65

Independent Director Since 2018
Audit Committee
Nominating and Governance Committee

Mr. Ryan, through his position as executive vice president and general counsel at Marriott International, Inc., brings extensive experience to our board in acquisitions, contracts, compliance, legal matters, SEC reporting, and labor relations. Mr. Ryan's experience significantly contributes to the board's oversight of compliance and corporate governance.

Career Highlights

- Advisor to the chief executive officer and president of Marriott International from December 2017 to December 31, 2018.
- Executive vice president and general counsel of Marriott International from December 2006 to December 2017; senior vice president and associate general counsel from 1999 to November 2006; assumed responsibility for all corporate transactions and corporate governance in 2005; and joined Marriott International as assistant general counsel in May 1996.
- Private law practice from 1979 to 1996.

Other Leadership Experience

- Director of Goodwill of Greater Washington, D.C., a non-profit organization whose mission is to transform lives and communities through education and employment, since January 2015, as well as vice chair since January 2019 and chair of the finance committee since January 2018.

Education

- Juris doctor degree from the University of Pennsylvania Law School.
- Bachelor's degree in economics and international relations from the University of Pennsylvania.

David M. Sparby

Age 64

Independent Director Since 2018
Audit Committee

Mr. Sparby has over 32 years of broad public utility experience through his positions as senior vice president and group president, revenue, of Xcel Energy Inc., president and chief executive officer of its subsidiary, Northern States Power-Minnesota (NSP-Minnesota), and chief financial officer of Xcel Energy. Mr. Sparby's public utility and renewable energy expertise contributes to the board's knowledge of the public utility and natural gas pipeline industries.

Career Highlights

- Senior vice president and group president, revenue, of Xcel Energy and president and chief executive officer of its subsidiary, NSP-Minnesota, from May 2013 until his retirement in December 2014; senior vice president and group president, from September 2011 to May 2013; chief financial officer from March 2009 to September 2011; and president and chief executive officer of NSP-Minnesota from 2008 to March 2009. He joined Xcel Energy, or its predecessor Northern States Power Company, as an attorney in 1982 and held positions of increasing responsibility.
- Attorney with the State of Minnesota, Office of Attorney General, from 1980 to 1982, during which period his responsibilities included representation of the Department of Public Service and the Minnesota Public Utilities Commission.

Other Leadership Experience

- Board of Trustees of Mitchell Hamline School of Law since July 2011, including executive committee and committee chair positions.
- Board of Trustees of the College of St. Scholastica since July 2012, including vice chair and executive committee positions.

Education

- Juris doctor degree from William Mitchell College of Law.
- Bachelor's degree in history from College of St. Scholastica and a master's degree in business administration from University of St. Thomas.

Chenxi Wang

Age 49

Independent Director Nominee

Ms. Wang has extensive technology and cybersecurity expertise through her experience, including founder and managing general partner of Rain Capital Fund, L.P., chief strategy officer at Twistlock, vice president, cloud security & strategy at Ciphercloud, and vice president, strategy and market intelligence at Intel Security. She is a sought-after public speaker on issues of technology and cybersecurity.

Career Highlights

- Founder and managing general partner of Rain Capital Fund, L.P., a cybersecurity-focused venture fund aiming to fund early-stage, transformative technology innovations in the security market with a goal of supporting women and minority entrepreneurs, since December 2017.
- Chief strategy officer at Twistlock, an automated and scalable cloud native cybersecurity platform, from August 2015 to February 2017.
- Vice president, cloud security & strategy of CipherCloud, a cloud security software company, from January 2015 to August 2015.
- Vice president of strategy of Intel Security, a company focused on developing proactive, proven security solutions and services that protect systems, networks, and mobile devices, from April 2013 to January 2015.
- Principal analyst and vice president of research at Forrester Research, a market research company that provides advice on existing and potential impact of technology, from January 2007 to April 2013.
- Assistant research professor and associate professor of computer engineering at Carnegie Mellon University from September 2001 through August 2007.

Other Leadership Experience

- Board of directors of OWASP Global Foundation, a nonprofit global community that drives visibility and evolution in the safety and security of the world's software, since January 2018 and vice chair from January 2018 to December 2018.
- Board of advisors of Keyp GmbH, a Munich-based software company with a mission to provide enterprises convenient access to the digital identity ecosystem, since December 2017.
- Program co-chair (security and privacy track) for the Grace Hopper Conference 2016 and 2017, the world's largest gathering of women in computing.

Education

- Doctor of Philosophy (Ph.D.) in computer science from University of Virginia.
- Bachelor's degree in computer science from Lock Haven University of Pennsylvania.

John K. Wilson
Age 64

Independent Director Since 2003
Audit Committee

Mr. Wilson has an extensive background in finance and accounting, as well as experience with mergers and acquisitions, through his education and work experience at a major accounting firm and his later public utility experience in his 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. Mr. Wilson contributes business management and public utility knowledge to our board.

Career Highlights

- President of Durham Resources, LLC, a privately held financial management company, in Omaha, Nebraska, from 1994 to December 31, 2008; president of Great Plains Energy Corp., a public utility holding company and an affiliate of Durham Resources, LLC, from 1994 to July 1, 2000; and vice president of Great Plains Natural Gas Co., an affiliate company of Durham Resources, LLC, until July 1, 2000.
- Executive director of the Robert B. Daugherty Foundation in Omaha, Nebraska, since January 2010.
- Held positions of 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.

Other Leadership Experience

- Director of HDR, Inc., an international architecture and engineering firm, since December 2008; and director of Tetrad Corporation, a privately held investment company, since April 2010, both located in Omaha, Nebraska.
- Former director of Bridges Investment Fund, Inc., a mutual fund, from April 2003 to April 2008; director of the Greater Omaha Chamber of Commerce from January 2001 through December 2008; member of the advisory board of U.S. Bank NA Omaha from January 2000 to July 2010; and the advisory board of Duncan Aviation, an aircraft service provider, headquartered in Lincoln, Nebraska, from January 2010 to February 2016.

Education and Professional

- Bachelor's degree in business administration, cum laude, from the University of Nebraska – Omaha.
- Certified public accountant, on inactive status.

Additional Information - Majority Voting

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 on how to vote. Please be sure to give specific voting instructions to your broker so your vote can be counted.

Board Evaluations and Process for Selecting Directors

In the annual board evaluation process, the nominating and governance committee evaluates our directors considering the current needs of the board and the company. In addition, during the year, the committee discusses board succession and reviews potential candidates. The committee may also retain a third party to assist in identifying potential nominees; none were retained in 2018.

Our annual board evaluation process involves assessments at the board and board committee levels. These annual evaluations are conducted by the chair of the nominating and governance committee and periodically by an independent third party.

Our governance guidelines provide that directors are not eligible to be nominated or appointed to the board if they are 76 years or older at the time of the election or appointment. Term limits on directors' service have not been instituted.

Director Qualifications, Skills, and Experience

Director nominees are chosen to serve on the board based on their qualifications, skills, and experience, as discussed in their biographies, and how those characteristics supplement the resources and talent on the board and serve the current needs of the board and the company.

In making its nominations, the nominating and governance committee also assesses each director nominee by a number of key characteristics, including character, success in a chosen field of endeavor, background in publicly traded companies, independence, and willingness to commit the time needed to satisfy the requirements of board and committee membership. Although the committee has no formal policy regarding diversity, the committee also considers diversity in gender, ethnic background, geographic area of residence, skills, and professional experience in recommending director nominees.

The following shows core specialized competencies and other characteristics of the director nominees.

CORE SPECIALIZED COMPETENCES

EXECUTIVE MANAGEMENT/PUBLIC COMPANY
Served as CEO or other senior executive of an organization or as a director of another publicly traded company

100%

INDUSTRY EXPERIENCE
Experience in our businesses and related industries, including public utilities, natural gas pipelines, construction, engineering, aggregate mining

70%

ACCOUNTING/FINANCE
Experience in the preparation and review of financial statements and financial reports

60%

LEGAL/CORPORATE GOVERNANCE
Experience in dealing with complex legal and public company governance issues

60%

CAPITAL MARKETS
Experience overseeing company financings, investments, capital structures, and financial strategy

70%

ENVIRONMENT/SCIENCE
Experience addressing environmental and sustainability issues relating to our businesses

30%

INFORMATION TECHNOLOGY/CYBERSECURITY
Oversight of or significant background working with information technology systems, data management and cybersecurity risks

10%

GOVERNMENT/REGULATORY/PUBLIC AFFAIRS
Background or experience in governmental regulations and public policy issues affecting our businesses

60%

RISK MANAGEMENT AND COMPLIANCE
Regulatory and compliance expertise or experience in the identification, assessment and mitigation of risks facing our company

100%

INDEPENDENCE

The company's corporate governance guidelines require that a substantial majority of the board must be independent. The board has determined that all director nominees, other than Mr. Goodin, meet the independence standards set by the NYSE and SEC.

90%

Nominee Independence

TENURE

The average tenure of the director nominees is approximately 9.5 years, which reflects a balance of company experience and new perspectives.

# of Years of Service

0-4

5-10

11+

GENDER DIVERSITY

The board is committed to having a diverse and broadly inclusive membership. Three of our 10 director nominees are women.

70% **30%**

Board Composition and Refreshment

The nominating and governance committee is focused on ensuring that the board reflects a diversity of experience, skills, and backgrounds. Each of the current directors, other than Harry J. Pearce and William E. McCracken, has been nominated for election to the board of directors upon recommendation by the nominating and governance committee and each has decided to stand for election. Messrs. Pearce and McCracken were not eligible for re-election under the company's age limit policy that provides no individual is eligible for election to the board of directors after his or her 76th birthday.

With the retirement of former board member A. Bart Holaday at the annual meeting in May 2018 and Harry J. Pearce and William E. McCracken reaching our board retirement age limit and retiring from the board at our 2019 annual meeting, the committee identified qualified diverse director candidates with commensurate experience and background as replacement board members.

In evaluating the board retirements and current needs of the board and the company, the nominating and governance committee focused on identifying board candidates that would add gender diversity to the board as well as background and core competencies in the fields of regulated energy delivery, technology and cybersecurity, and public company governance. Potential director nominees were brought to the attention of the nominating and governance committee by board members, management, organizations, and database searches.

In 2018, the nominating and governance committee identified a need for additional expertise in the operation of electric and natural gas utilities and natural gas transmission pipelines. At December 31, 2018, approximately 66% of our capital was invested in these business segments which generated approximately 28% of our 2018 revenues. After serving in several positions during his 32-year career with Xcel Energy, including chief financial officer, and most recently as senior vice president, revenue group, and chief executive officer of its subsidiary, Northern States Power-Minnesota, David M. Sparby brings a vast amount of experience related to the electric and natural gas distribution and pipeline industries. Mr. Sparby was appointed to the board of directors on August 16, 2018.

With the anticipated retirement of Harry J. Pearce, the nominating and governance committee identified a director nominee with extensive risk management and public company governance experience. Prior to his retirement in 2017, Edward A. Ryan served as executive vice president and general counsel for Marriott International, Inc. where his responsibilities included chair of the company's legal and ethical steering and enterprise crisis management committees. Mr. Ryan was appointed to the board of directors on November 15, 2018.

With the anticipated retirement of William E. McCracken, the nominating and governance committee identified a director nominee that would bring diversity as well as technology and cybersecurity expertise to the board. Chenxi Wang has held positions with various organizations related to technology and security software and is a frequent speaker on issues of technology and cybersecurity. She is currently the founder and general partner of Rain Capital Fund, L.P., an early stage venture capital firm focused on cybersecurity innovation and artificial intelligence for its clients and the promotion of women entrepreneurs. Ms. Wang also provides gender, ethnic, age, and geographic diversity to the board.

By tenure, if the nominees are elected, the board will comprise of three directors who have served from 0-4 years, two directors who have served from 5-10 years, and five directors who have served over 11 years. This mix provides a balance of experience and institutional knowledge with fresh perspectives.

CORPORATE GOVERNANCE AND THE BOARD OF DIRECTORS

Director Independence

The board of directors has adopted guidelines on director independence that are included in our corporate governance guidelines. Our guidelines require that a substantial majority of the board consists of independent directors. In general, the guidelines require that an independent director must have no material relationship with the company directly or indirectly, except as a director. The board determines independence on the basis of the standards specified by the New York Stock Exchange (NYSE), the additional standards referenced in our corporate governance guidelines, and other facts and circumstances the board considers relevant. Based on its review, the board has determined that all directors and director nominees, except for our chief executive officer Mr. Goodin, have no material relationship with us and are independent.

In determining director independence, the board of directors reviewed and considered information about any transactions, relationships, and arrangements between the non-employee directors and director nominees 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:

- Charitable contributions by the MDU Resources Foundation (Foundation) to nonprofit organizations where a director, a director nominee, or their 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 four nonprofit organizations that collectively amounted to $27,500 in 2018. None of the contributions made to any of the nonprofit entities exceeded the greater of $1 million or 2% of the relevant entity's consolidated gross revenues.

- Business relationships with entities with which a director or director nominee is affiliated: Mr. Wilson is a member of the board of directors of HDR, Inc., an architectural, engineering, environmental, and consulting firm. The company paid HDR, Inc. or its affiliates approximately $1 million in 2018 directly or through a third party for services which were provided in the ordinary course of business and on substantially the same terms prevailing for comparable services from other consulting firms. Mr. Wilson had no role in securing or promoting the HDR, Inc. services.

The board has also determined that all members of the audit, compensation, and nominating and governance committees of the board are independent in accordance with our guidelines and applicable NYSE and Securities Exchange Act of 1934 rules.

Stockholder Engagement

The company has an active stockholder outreach program. We believe in providing transparent and timely information to our investors. Each year we routinely engage directly or indirectly with our stockholders, including our top institutional stockholders. During 2018, the company held meetings, conference calls, and webcasts with a diverse mix of stockholders. Throughout the year, we held meetings or telephone conferences with eleven of the institutional investors included in our year-end top 30 stockholders. In our meetings or conferences, we discussed a variety of topics including longer-term company strategy and our capital expenditure forecast; shorter-term operational and financial updates; environmental, social, and corporate governance; and previously announced strategic initiatives. The company also held telephone conferences with a proxy advisory firm to discuss corporate governance, executive compensation practices, and other topics.

Board Leadership Structure

The board separated the positions of chair of the board and chief executive officer in 2006, and our bylaws and corporate governance guidelines currently require that our chair be independent. The board believes this structure provides balance and is currently in the best interest of the company and its stockholders. Separating these positions allows the chief executive officer to focus on the full-time job of running our business, while allowing the chair of the board to lead the board in its fundamental role of providing advice to and independent oversight of management. The chair meets regularly between board meetings with the chief executive officer and consults with the chief executive officer regarding the board meeting agendas, the quality and flow of information provided to the board, and the effectiveness of the board meeting process. The board believes this split structure recognizes the time, effort, and energy the chief executive officer is required to devote to the position in the current business environment, as well as the commitment required to serve as the chair, 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 chair is a means to ensure the chief executive officer is accountable for managing the company in close alignment with the interests of stockholders, including with respect to risk management as discussed below. An independent chair is in a position to encourage frank and lively discussions, including during regularly scheduled executive sessions consisting of only independent directors, and to assure that the company has adequately assessed all appropriate business risks before adopting its final business plans and strategies. The board believes that having separate positions and having an independent outside director serve as chair is the appropriate leadership structure for the company at this time and demonstrates our commitment to good corporate governance. With the retirement of Mr. Pearce at the annual meeting, the board will elect a new independent chair at its May board meeting.

Board's Role in Risk Oversight

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, operational risks, environmental and regulatory risks, the impact of competition, climate and weather conditions, limitations on our ability to pay dividends, pension plan obligations, cyberattacks or acts of terrorism, and third party liabilities. Management is responsible for identifying material risks, implementing appropriate risk management strategies, and providing information regarding material risks and risk management to the board. 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 for identifying, assessing, and managing risk.

The board believes establishing the right "tone at the top" and full and open communication between management and the board of directors are essential for effective risk management and oversight. Our chair meets regularly with our chief executive officer 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. Senior management annually presents an assessment to the board of critical enterprise risks that threaten the company's strategy and business model, including risks inherent in the key assumptions underlying the company's business strategy for value creation. Periodically, the board receives presentations from external experts on matters of strategic importance to the board. In 2018, the board heard presentations from external experts regarding climate change and its risks and opportunities, oil and natural gas exploration in the Bakken geological formation in North Dakota, and projected natural gas processing and transportation needs in North Dakota. At least annually, the board holds strategic planning sessions with senior management to discuss strategies, key challenges, and risks and opportunities for the company.

The company has also developed a robust compliance program to promote a culture of compliance, consistent with the right tone at the top, to mitigate risk. The program includes training and adherence to our code of conduct and legal compliance guide. We further mitigate risk through our internal audit and legal departments.

While the board is ultimately responsible for risk oversight at our company, our three standing 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 management in a general manner and specifically in the areas of financial reporting, internal controls, cybersecurity, and compliance with legal and regulatory requirements, and, in accordance with NYSE requirements, discusses with the board policies with respect to risk assessment and risk management and their adequacy and effectiveness. The audit committee receives regular reports on the company's compliance program, including reports received through our anonymous reporting hot line. It also receives reports and regularly meets with the company's external and internal auditors. During each of its quarterly meetings in 2018, the audit committee received presentations from management on cybersecurity and the company's mitigation of cybersecurity risks. The entire board was present for these presentations. Risk assessment and mitigation 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 such exposure, 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 2018, the board of directors held four regular meetings and two special meetings. Each director attended at least 75% of the combined total meetings of the board and the committees on which the director served during 2018 (held during the period he or she has been a director). Directors are encouraged to attend our annual meeting of stockholders. All directors attended our 2018 Annual Meeting of Stockholders.

The non-employee directors meet in executive session at each regularly scheduled quarterly board of directors meeting. The chair of the board presides at the executive session of the non-employee directors held in connection with each regularly scheduled quarterly board of directors meeting.

The board has standing audit, compensation, and nominating and governance committees. The table below provides current committee membership.

Name	Audit Committee	Compensation Committee	Nominating and Governance Committee
Thomas Everist		C	
Karen B. Fagg		●	C
Mark A. Hellerstein	●		
Dennis W. Johnson	C		●
William E. McCracken		●	●
Patricia L. Moss		●	●
Edward A. Ryan	●		●
David M. Sparby	●		
John K. Wilson	●		

C - Chair

● - Member

Below is a description of each standing committee of the board. The board has affirmatively determined that each of these standing committees consists entirely of independent directors pursuant to rules established by the NYSE, rules promulgated under the Securities and Exchange Commission (SEC), and the director independence standards established by the board. The board has also determined that each member of the audit committee and the compensation committee is independent under the criteria established by the NYSE and the SEC for audit committee and compensation committee members, as applicable.

Nominating and Governance Committee

Met Six Times in 2018

The nominating and governance committee met six times during 2018. The committee members are Karen B. Fagg, chair, Dennis W. Johnson, William E. McCracken, Patricia L. Moss, and Edward A. Ryan.

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
- our corporate governance guidelines.

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, 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 in the same manner we consider other nominees. Stockholders who wish to recommend a director candidate may submit recommendations, along with the information set forth in the guidelines, to the nominating and governance committee chair in care of the secretary at MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506-5650.

Stockholders who wish to nominate persons for election to our board at an annual meeting of stockholders must follow the applicable procedures set forth in Section 2.08 or 2.10 of our bylaws. Our bylaws are available on our website. See "Stockholder Proposals, Director Nominations, and Other Items of Business for 2020 Annual Meeting" in the section entitled "Information about the Annual Meeting" for further details.

In evaluating director candidates, the committee, in accordance with our corporate governance guidelines, 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, business management, human resources, marketing, operations, public affairs, law, technology, risk management, governance, and operations abroad;
- background in publicly traded companies including service on other public company boards of directors;
- 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
- compliance with applicable law and applicable corporate governance, code of conduct and ethics, conflict of interest, corporate opportunities, confidentiality, stock ownership and trading policies, and other policies and guidelines of the company.

In addition, our bylaws contain requirements that a person must meet to qualify for service as a director.

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 and the board nominees reflects diversity in business and professional experience, skills, ethnicity, gender, and geography.

Audit Committee

Met Eight Times in 2018

The audit committee is a separately-designated committee established in accordance with Section 3(a)(58)(A) of the Securities Exchange Act of 1934.

The audit committee met eight times during 2018. The audit committee members are Dennis W. Johnson, chair, Mark A. Hellerstein, Edward A. Ryan, David M. Sparby, and John K. Wilson. The board of directors has determined that Messrs. Johnson, Hellerstein, Sparby, and Wilson are "audit committee financial experts" as defined by SEC rules and all audit committee members are financially literate within the meaning of the listing standards of the NYSE. All members also meet the independence standard for audit committee members under our director independence guidelines, the NYSE listing standards, and SEC rules.

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;
  - the company's compliance with legal and regulatory requirements and the code of conduct;
  - the independent registered public accounting firm's qualifications and independence;
  - the performance of our internal audit function and independent registered public accounting firm;
  - management of risk in the audit committee's areas of responsibility; and
- arranges for the preparation of and approves the report that SEC rules require we include in our annual proxy statement. See the section entitled "Audit Committee Report" for further information.

Compensation Committee

Met Four Times in 2018

During 2018, the compensation committee met four times. The compensation committee consists entirely of independent directors within the meaning of the company's corporate governance guidelines and the NYSE listing standards and who meet the definitions of non-employee directors for purposes of Rule 16-b under the Exchange Act. Members of the compensation committee are Thomas Everist, chair, Karen B. Fagg, William E. McCracken, and Patricia L. Moss.

The compensation committee assists the board of directors in fulfilling its responsibilities relating to the company's compensation policy and programs. It has the direct responsibility for determining compensation for our Section 16 officers and for overseeing the company's management of risk in its areas of responsibility. In addition, the compensation committee reviews and recommends any changes to director compensation policies to the board of directors. The authority and responsibility of the compensation committee is outlined in the compensation committee's charter.

The compensation committee uses the analysis and recommendations from outside consultants, the chief executive officer, and the human resources department in making its compensation decisions. The chief executive officer, the vice president-human resources, and the general counsel regularly attend compensation committee meetings. The committee meets in executive session as needed. The processes and procedures for consideration and determination of compensation of the Section 16 officers, as well as the role of our executive officers, are discussed in the "Compensation Discussion and Analysis."

The compensation committee has sole authority to retain 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, and the committee is directly responsible for the appointment, compensation, and oversight of the work of such advisers. The compensation committee's practice has been to retain a compensation consultant every other year to conduct a competitive analysis on executive compensation. The competitive analysis is conducted internally by the human resources department in the other years. In 2018, the compensation committee retained a compensation consultant, Meridian Compensation Partners, LLC, to conduct a competitive analysis on executive compensation for 2019. Prior to retaining an adviser, the compensation committee considers all factors relevant to ensure the adviser's independence from management. Annually the compensation committee conducts a potential conflicts of interest assessment raised by the work of any compensation consultant and how such conflicts, if any, should be addressed. The compensation committee requested and received information from Meridian Compensation Partners, LLC to assist in its potential conflicts of interest assessment. Based on its review and analysis, the compensation committee determined in 2018 that Meridian Compensation Partners, LLC was independent from management.

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 2018, the analysis of non-employee director compensation was performed by the human resources department. Meridian Compensation Partners, LLC will conduct the analysis in 2019.

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 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, the human resources department identified the principal areas of risk faced by the company that may be affected by our compensation policies and practices, 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 promotes careful consideration of financial assumptions;

  - limitation on business acquisitions without board approval;
  - employee integrity training programs and anonymous reporting systems;
  - quarterly risk assessment reports at audit committee meetings; and
  - prohibitions on holding company stock in an account that is subject to a margin call, pledging company stock as collateral for a loan, and hedging of company stock by Section 16 officers and directors.

- Executive compensation practices:
  - active compensation committee review of executive compensation, including portions of executive compensation based upon the company's total stockholder return in relation to that of the company's peer group;
  - 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 and long-term incentives tied primarily to the company's financial and stock performance;
  - use of interpolation for annual and long-term incentive awards to avoid payout cliffs;
  - negative discretion to adjust any annual incentive award payment downward;
  - use of caps on annual incentive awards (maximum of 200% for regulated segments and 240% for construction materials and services segments) and long-term incentive stock grant awards (200% of target);
  - ability to clawback incentive payments in the event of a financial restatement;
  - use of performance shares and restricted stock units, rather than stock options or stock appreciation rights, as an equity component of incentive compensation;
  - use of performance shares for long-term incentive awards with relative total stockholder return, earnings before interest, taxes, depreciation, and amortization (EBITDA) growth, and earnings growth performance components;
  - use of three-year performance periods for long-term incentive awards to discourage short-term risk-taking;
  - substantive annual incentive goals measured primarily by earnings, EBITDA, 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 peer group;
  - stock ownership requirements for the board and for executives receiving long-term incentive awards;
  - mandatory holding periods for 50% of any net after-tax shares earned under long-term incentive awards; and
  - use of independent consultants to assist in establishing pay targets and compensation structure at least biennially.

Stockholder Communications with the Board

Stockholders and other interested parties who wish to contact the board of directors or any individual director, including our non-employee chair 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.

Additional Governance Features

Board and Committee Evaluations

Our corporate governance guidelines provide that the board of directors, in coordination with the nominating and governance committee, will annually review and evaluate the performance and functioning of the board and its committees. The self-evaluations are intended to facilitate a candid assessment and discussion by the board and each committee of its effectiveness as a group in fulfilling its responsibilities, its performance as measured against the corporate governance guidelines, and areas for improvement. The board and committee members are provided with a questionnaire to facilitate discussion. The results of the evaluations are reviewed and discussed in executive sessions of the committees and the board of directors.

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 2018, no directors or director nominees submitted resignations under this requirement.

Majority Voting in Uncontested Director Elections

Our corporate governance guidelines require that in uncontested elections (those where the number of nominees does not exceed the number of directors to be elected), director nominees must receive the affirmative vote of a majority of the votes cast to be elected to our board of directors. Contested director elections (those where the number of director nominees exceeds the number of directors to be elected) are governed by a plurality of the vote of shares present in person or represented by proxy at the meeting.

The board has adopted a director resignation policy for incumbent directors in uncontested elections. Any proposed nominee for re-election as a director shall, before he or she is nominated to serve on the board, tender to the board his or her irrevocable resignation that will be effective, in an uncontested election of directors only, upon (i) such nominee's receipt of a greater number of votes "against" election than votes "for" election at our annual meeting of stockholders; and (ii) acceptance of such resignation by the board of directors.

Director Overboarding Policy

Our bylaws and corporate governance guidelines state that a director may not serve on more than three public company boards, including the company's board. Currently, all of our directors are in compliance of this policy.

Board Refreshment

The company regularly evaluates the need for board refreshment. The nominating and governance committee and the board are focused on identifying individuals whose skills and experiences will enable them to make meaningful contributions to shaping the company's business strategy. As part of its consideration of director succession, the nominating and governance committee from time to time reviews, including when considering potential candidates, the appropriate skills and characteristics required of board members. The board believes it is important to consider diversity of skills, expertise, race, ethnicity, gender, age, education, geography, cultural background, and professional experiences in evaluating board candidates for expected contributions to an effective board. Independent directors may not serve on the board beyond the next annual meeting of stockholders after attaining the age of 76. We believe the mandatory retirement age allows us to benefit from experienced directors, with industry expertise, company institutional knowledge and historical perspective, stability, and comfort with challenging company management, while maintaining our ability to refresh the board through the addition of new members. In connection with our mandatory retirement for directors, Harry J. Pearce and William E. McCracken will retire as directors at the completion of their current term following the 2019 annual meeting.

Prohibitions on Hedging/Pledging Company Stock

The director compensation policy prohibits directors from hedging their ownership of common stock, pledging company stock as collateral for a loan, or holding company stock in an account that is subject to a margin call.

Code of Conduct

We have a code of conduct and ethics, which we refer to as the Leading With Integrity Guide. It applies to all directors, officers, and employees.

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 NYSE listing standards, by posting such information on our website.

Proxy Access

In February 2018, the board of directors amended our bylaws to implement proxy access with the following parameters:

Ownership Threshold:	3% of outstanding shares of our common stock
Nominating Group Size:	Up to 20 stockholders may combine to reach the 3% ownership threshold
Holding Period:	Continuously for three years
Number of Nominees:	The greater of two nominees or 20% of our board

We believe these proxy access parameters reflect a well designed and balanced approach to proxy access that mitigates the risk of abuse and protects the interests of all of our stockholders. Stockholders who wish to nominate directors for inclusion in our Proxy Statement in accordance with proxy access must follow the procedures in Section 2.10 of our bylaws. See "Stockholder Proposals, Director Nominations, and Other Items of Business for 2020 Annual Meeting."

Corporate Governance Materials

Stockholders can see our bylaws, corporate governance guidelines, board committee charters, and Leading With Integrity Guide on our website.

Corporate Governance Materials	Website
• Bylaws	http://www.mdu.com/governance
• Corporate Governance Guidelines	http://www.mdu.com/governance
• Board Committee Charters for the Audit, Compensation, and Nominating and Governance Committees	http://www.mdu.com/governance
• Leading With Integrity Guide	http://www.mdu.com/commitmenttointegrity

Related Person Transaction Disclosure

The board of directors' policy for the review of related person transactions is contained in our corporate governance guidelines. The policy requires the audit committee to review any transaction, arrangement or relationship, or series thereof:

- in which the company was or will be a participant;
- the amount involved exceeds $120,000; and
- a related person had or will have a direct or indirect material interest.

The purpose of this review is to determine whether this transaction is in the best interests of the company.

Related persons are directors, director nominees, executive officers, holders of 5% or more of our voting stock, and their immediate family members. Related persons are required promptly to report to our general counsel all proposed or existing related person transactions in which they are involved.

If our general counsel determines that the transaction is required to be disclosed under the SEC rules, the general counsel furnishes the information to the chair of the audit committee. 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.

We had no related person transactions in 2018.

COMPENSATION OF NON-EMPLOYEE DIRECTORS

Director Compensation for 2018

MDU Resources' non-employee directors are compensated for their service according to the MDU Resources Group Inc. Director Compensation Policy. Only one company employee, David L. Goodin, the company's president and chief executive officer, serves as a director. Mr. Goodin receives no additional compensation for his service on the board. Director compensation is reviewed annually by the compensation committee with analysis provided by an independent consultant in odd numbered years and analysis prepared by the company's human resources department in even numbered years. The company's human resources department provided the director compensation analysis for 2018. The analysis included research on market trends in director compensation as well as a review of director compensation practices of our peer group companies. Based on the analysis, the compensation committee recommended and the board concurred that no changes would be made to board member compensation for 2018. The following table outlines the compensation paid to our non-employee directors for 2018.

Name	Fees Earned or Paid in Cash ($)	Stock Awards ($)[1]	All Other Compensation ($)[2]	Total ($)
Thomas Everist	80,000	110,000	83	190,083
Karen B. Fagg	80,000	110,000	583	190,583
Mark A. Hellerstein	70,000	110,000	83	180,083
A. Bart Holaday	29,167	45,833	35	75,035
Dennis W. Johnson	85,000	110,000	83	195,083
William E. McCracken	70,000	110,000	83	180,083
Patricia L. Moss	70,000	110,000	83	180,083
Harry J. Pearce	160,000	145,000	83	305,083
Edward A. Ryan	11,667	18,333	7	30,007
David M. Sparby	29,167	45,833	28	75,028
John K. Wilson	70,000	110,000	83	180,083

1 Directors receive an annual payment of $110,000 in company common stock, except the non-executive chair who receives $145,000 in company common stock, under the MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan. Directors serving less than a full year receive a prorated stock payment based on the number of months served. All stock payments are measured in accordance with Financial Accounting Standards Board (FASB) 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 of November 20, 2018, which was $26.55 per share. The amount paid in cash for fractional shares is included in the amount reported in the stock awards column to this table. As of December 31, 2018, there are no outstanding stock awards or options associated with the Non-Employee Director Long-Term Incentive Compensation Plan.

2 Includes group life insurance premiums and charitable donations made on behalf of the director as applicable. Amounts for life insurance premiums reflect prorated amounts for directors serving less than a full year based on the number of months served.

The following table shows the annual cash and stock retainers payable to our non-employee directors.

Base Cash Retainer	$ 70,000
Additional Cash Retainers:	
Non-Executive Chair	90,000
Audit Committee Chair	15,000
Compensation Committee Chair	10,000
Nominating and Governance Committee Chair	10,000
Annual Stock Grant[1] - Directors (other than Non-Executive Chair)	110,000
Annual Stock Grant[2] - Non-Executive Chair	145,000

[1] The annual stock grant is a grant of shares of company common stock equal in value to $110,000.

[2] The annual stock grant is a grant of shares of company common stock equal in value to $145,000.

There are no meeting fees paid to directors.

Other Compensation

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 their beneficiaries during the time they serve on the board. The annual cost per director is $82.80. Directors who contribute to the company's Good Government Fund may designate up to two charities to receive a matching donation from the MDU Resources Foundation based on their contributions to the fund. Directors are reimbursed for all reasonable travel expenses, including spousal expenses in connection with attendance at meetings of the board and its committees. Perquisites, if any, were below the disclosure threshold in 2018.

Deferral of Compensation

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.

Post-Retirement

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.

Stock Ownership Policy

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 received through our Non-Employee Director Long-Term Incentive Plan are considered in ownership calculations as is ownership of our common stock by a spouse. A director is allowed five years commencing January 1 of the year following the year of the 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. All directors are in compliance with the stock ownership policy or are within the first five years of their election to the board. For further details on our director's stock ownership, see the section entitled "Security Ownership."

SECURITY OWNERSHIP

Security Ownership Table

The table below sets forth the number of shares of our common stock that each director and each nominee for director, each current named executive officer, and all directors and executive officers as a group owned beneficially as of February 28, 2019. Unless otherwise indicated, each person has sole investment and voting power (or share such power with his or her spouse) of the shares noted.

Name[1]	Shares of Common Stock Beneficially Owned	Percent of Class
David C. Barney	44,313 [2,3]	*
Thomas Everist	861,692	*
Karen B. Fagg	73,314	*
David L. Goodin	264,925 [2]	*
Mark A. Hellerstein	24,000	*
Dennis W. Johnson	92,352 [4]	*
Nicole A. Kivisto	59,635 [2,5]	*
William E. McCracken	24,000	*
Patricia L. Moss	76,328	*
Harry J. Pearce	246,740	*
Edward A. Ryan	10,690	*
David M. Sparby	1,726	*
Jeffrey S. Thiede	43,540 [2]	*
Jason L. Vollmer	11,374 [2]	*
Chenxi Wang	—	*
John K. Wilson	129,601	*
All directors and executive officers as a group (20 in number)	2,069,126 [2,6]	1.05 %

* Less than one percent of the class. Percent of class is calculated based on 196,338,488 outstanding shares as of February 28, 2019.

1 The table includes the ownership of all current directors, director nominees, current named executive officers, and other executive officers of the company without naming them.

2 Includes full shares allocated to the officer's account in our 401(k) retirement plan.

3 The total includes 687 shares owned by Mr. Barney's spouse.

4 Mr. Johnson disclaims all beneficial ownership of the 163 shares owned by his spouse.

5 The total includes 531 shares owned by Ms. Kivisto's spouse.

6 Includes shares owned by a director's or executive's spouse regardless of whether the director or executive claims beneficial ownership.

Hedging Policy

The company's Director Compensation Policy and its Executive Compensation Policy prohibit our directors and executives from hedging their ownership of company stock. The Director Compensation Policy applies to all directors who are not full-time employees of the company. The Executive Compensation Policy applies to the executives of the company designated as an officer for purposes of Section 16 of the Securities Exchange Act of 1934 as well as all other executives of the company and its subsidiaries who participate in its Long-Term Performance-Based Incentive Plan and its Executive Incentive Compensation Plan. Under the policies, directors and executives are prohibited from engaging in transactions that allow them to own stock technically but without the full benefits and risks of such ownership, including, but not limited to, zero-cost collars, equity swaps, straddles, prepaid variable forward contracts, security futures contracts, exchange funds, forward sale contracts, and other financial transactions that allow the director or executive to benefit from the devaluation of the company's stock.

The company policies also prohibit directors, executives, and related persons from holding company 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.

Greater Than 5% Beneficial Owners

Based solely on filings with the SEC, the table below shows information regarding the beneficial ownership of more than five percent of the outstanding shares of our common stock.

Title of Class	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Common Stock	The Vanguard Group 100 Vanguard Blvd. Malvern, PA 19355	21,436,898 [1]	10.93 %
Common Stock	BlackRock, Inc. 55 East 52nd Street New York, NY 10055	18,376,417 [2]	9.40 %
Common Stock	State Street Corporation State Street Financial Center One Lincoln Street Boston, MA 02111	12,377,612 [3]	6.30 %

1 Based solely on the Schedule 13G, Amendment No. 7, filed on February 11, 2019, The Vanguard Group reported sole dispositive power with respect to 21,336,371 shares, shared dispositive power with respect to 100,527 shares, sole voting power with respect to 94,745 shares, and shared voting power with respect to 22,519 shares. These shares include 74,426 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 42,838 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.

2 Based solely on the Schedule 13G, Amendment No. 9, filed on February 6, 2019, BlackRock, Inc. reported sole voting power with respect to 17,339,702 shares and sole dispositive power with respect to 18,376,417 shares as the parent holding company or control person of BlackRock Life Limited, BlackRock International Limited, BlackRock Advisors, LLC, BlackRock (Netherlands) B.V., BlackRock Fund Advisors, BlackRock Institutional Trust Company, National Association, BlackRock Asset Management Ireland Limited, BlackRock Financial Management, Inc., BlackRock Asset Management Schweiz AG, BlackRock Investment Management, LLC, BlackRock Investment Management (UK) Limited, BlackRock Asset Management Canada Limited, BlackRock (Luxembourg) S.A., BlackRock Investment Management (Australia) Limited, BlackRock Advisors (UK) Limited, BlackRock Asset Management North Asia Limited, and BlackRock Fund Managers Ltd.

3 Based solely on the Schedule 13G, filed on February 14, 2019, State Street Corporation reported shared voting and dispositive power with respect to 12,377,612 shares as the parent holding company or control person of SSGA Funds Management, Inc., State Street Global Advisors Limited (UK), State Street Global Advisors LTD (Canada), State Street Global Advisors, Australia Limited, State Street Global Advisors Asia LTD, State Street Global Advisors Singapore LTD, State Street Global Advisors GmbH, State Street Global Advisors Ireland Limited, and State Street Global Advisors Trust Company.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16 of the Securities Exchange Act of 1934, as amended, requires officers, directors, and holders of more than 10% of our common stock to file reports of their trading in our equity securities with the SEC. 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 2018, or written representations that no Forms 5 were required, we believe that all such reports were timely filed.

EXECUTIVE COMPENSATION

ITEM 2. ADVISORY VOTE TO APPROVE THE COMPENSATION PAID TO THE COMPANY'S NAMED EX 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 an 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, the compensation committee and board of directors believe that the current executive compensation program directly links compensation of the named executive officers to our financial performance and aligns the interests of the named executive officers with those of our stockholders. The compensation committee and board of directors also believe that the executive compensation program provides the 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 the named executive officers on both an annual and long-term basis if they attain specified goals.

Our overall compensation program and philosophy for 2018 was built on a foundation of these guiding principles:

- we pay for performance, with over 60% of our 2018 total target direct compensation for the named executive officers in the form of performance-based incentive compensation;
- we review competitive compensation data for the named executive officers, to the extent available, and incorporate internal equity in the final determination of target compensation levels;
- we align executive compensation and performance by using annual performance incentives based on criteria that are important to stockholder value, including earnings, earnings per share, and earnings before interest, taxes, depreciation, and amortization (EBITDA); and
- we align executive compensation and performance by using long-term performance incentives based on total stockholder return relative to our peer group and financial measures important to company growth.

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 2018. Accordingly, the following resolution is submitted for stockholder vote at the 2019 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 of this Proxy Statement, 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 the named executive officers remains with the compensation committee and the board of directors, although the board and compensation committee will consider the outcome of this vote when making future compensation decisions. We intend to hold this advisory vote every year until at least the next stockholder advisory vote on the frequency of this vote.

The board of directors recommends a vote "for" the approval, on a non-binding advisory basis, of the compensation of the company's named executive officers, as disclosed in this Proxy Statement.

Approval of the compensation of the named executive officers requires the affirmative vote of a majority of the 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-vote shares are not entitled to vote on this proposal and, therefore, are not counted in the vote.

INFORMATION CONCERNING EXECUTIVE OFFICERS

Information concerning the executive officers, including their ages as of December 31, 2018, present corporate positions, and business experience during the past five years, is as follows:

Name	Age	Present Corporate Position and Business Experience
David L. Goodin	57	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 the section entitled "Item 1. Election of Directors."
David C. Barney	63	Mr. Barney was elected president and chief executive officer of Knife River Corporation effective April 30, 2013, and president effective January 1, 2012.
Trevor J. Hastings	45	Mr. Hastings was elected president and chief executive officer of WBI Holdings, Inc. effective October 16, 2017. Prior to that, he was vice president-business development and operations support of Knife River Corporation effective January 11, 2012.
Anne M. Jones	55	Ms. Jones was elected vice president-human resources effective January 1, 2016. Prior to that, she was vice president-human resources, customer service, and safety at Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company effective July 1, 2013, and director of human resources for Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. effective June 2008.
Nicole A. Kivisto	45	Ms. Kivisto was elected president and chief executive officer of Montana-Dakota Utilities Co., Cascade Natural Gas Corporation, and Intermountain Gas Company effective January 9, 2015. Prior to that, she was vice president of operations for Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. effective January 3, 2014, and vice president, controller and chief accounting officer for the company effective February 17, 2010.
Daniel S. Kuntz	65	Mr. Kuntz was elected vice president, general counsel and secretary effective January 1, 2017. Prior to that, he was general counsel and secretary effective January 9, 2016, associate general counsel effective April 1, 2007, and assistant secretary effective August 17, 2007.
Margaret (Peggy) A. Link	52	Ms. Link was elected vice president and chief information officer effective December 1, 2017. Prior to that, she was chief information officer effective January 1, 2016, assistant vice president-technology and cybersecurity officer effective January 1, 2015, and director shared IT services effective June 2, 2009.
Jeffrey S. Thiede	56	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.
Jason L. Vollmer	41	Mr. Vollmer was elected vice president, chief financial officer and treasurer effective September 30, 2017. Prior to that, he was vice president, chief accounting officer and treasurer effective March 19, 2016, treasurer and director of cash and risk management effective November 29, 2014, manager of treasury services and risk management effective June 30, 2014, and manager of treasury services, cash and risk management effective April 11, 2011.

COMPENSATION DISCUSSION AND ANALYSIS

The Compensation Discussion and Analysis describes how our named executive officers were compensated for 2018 and how their 2018 compensation aligns with our pay for performance philosophy. It also describes the oversight of the compensation committee and the rationale and processes used to determine the 2018 compensation of our named executive officers including the objectives and specific elements of our compensation program.

The Compensation Discussion and Analysis may contain statements regarding corporate performance targets and goals. The 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.

Our Named Executive Officers for 2018 were:

David L. Goodin	President and Chief Executive Officer (CEO)
Jason L. Vollmer	Vice President, Chief Financial Officer (CFO) and Treasurer
David C. Barney	President and Chief Executive Officer - Construction Materials and Contracting Segment
Jeffrey S. Thiede	President and Chief Executive Officer - Construction Services Segment
Nicole A. Kivisto	President and Chief Executive Officer - Electric and Natural Gas Distribution Segments

Executive Summary

Pay for Performance

To ensure management's interests are aligned with those of our stockholders and the performance of the company, the majority of the CEO's and the other named executive officers' target compensation is dependent on the achievement of company performance targets. The charts below show the target pay mix for the CEO and average target pay mix of the other named executive officers, including base salary and the annual and long-term incentives.

*Includes time-vesting restricted stock units for certain named executive officers.

Annual Base Salary

We provide our executive officers with base salary at a sufficient level to attract, recruit, and retain executives with the knowledge, skills, and abilities necessary to successfully execute their job responsibilities. Consistent with our compensation philosophy of linking pay to performance, our executives receive a relatively smaller percentage of their overall target compensation in the form of base salary. In establishing base salaries, the compensation committee considers each executive's individual performance, the scope and complexities of their responsibilities, internal equity, and whether the base salary is competitive as measured against the base salaries of similarly situated executives in our peer group and market compensation data.

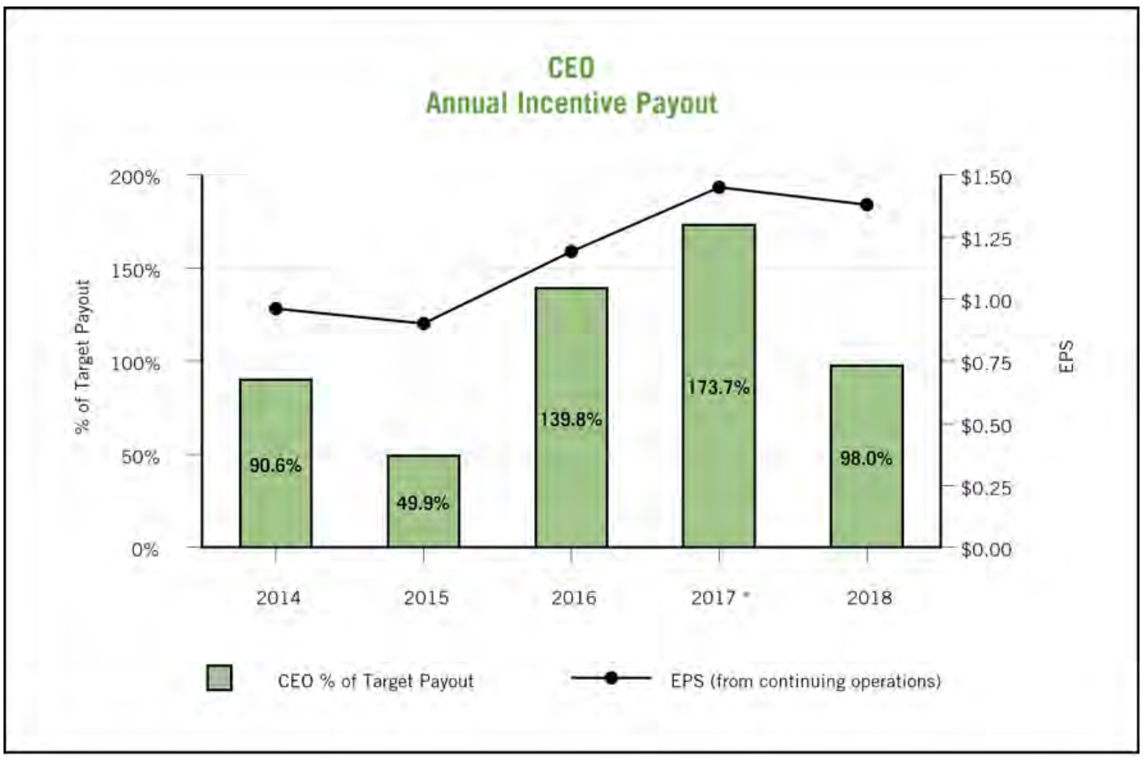
Annual Cash Incentive Awards

Annual cash incentive awards for our executive officers are linked to performance by rewarding achievement of financial goals and ensuring our executive officers are focused and accountable for our growth and profitability. The design of the annual cash incentive award opportunities for 2018 was the same as the design used in 2017. Each executive is assigned a target annual incentive award based on a percentage of the executive's base salary. The actual annual cash incentive realized is determined by multiplying the target award by the payout percentage associated with achievement of the executive's performance measures.

The compensation committee selected specific business segment financial performance measures for the business segment executives which represented 80% of their annual award opportunity. The other 20% of the business segment executives' annual award opportunity was based on the achievement of overall company earnings per share (EPS). These measures incentivize our business segment executives to focus on the success and performance of their business segment while keeping the overall success of the company in mind.

The annual cash incentive award for corporate executives (including our CEO and CFO) is based on the achievement of the performance measures for each business segment executive and weighted by each business segment's invested capital relative to the company's total invested capital. The corporate executives' target awards are multiplied by the sum of the weighted achievement percentage for each business segment executive to derive the corporate executives' realized annual awards. This incentivizes the corporate executives to assist the business segments in their success while still emphasizing overall company performance. See the "Annual Incentives" section within this Compensation Discussion and Analysis for further details on our company's annual cash incentive program.

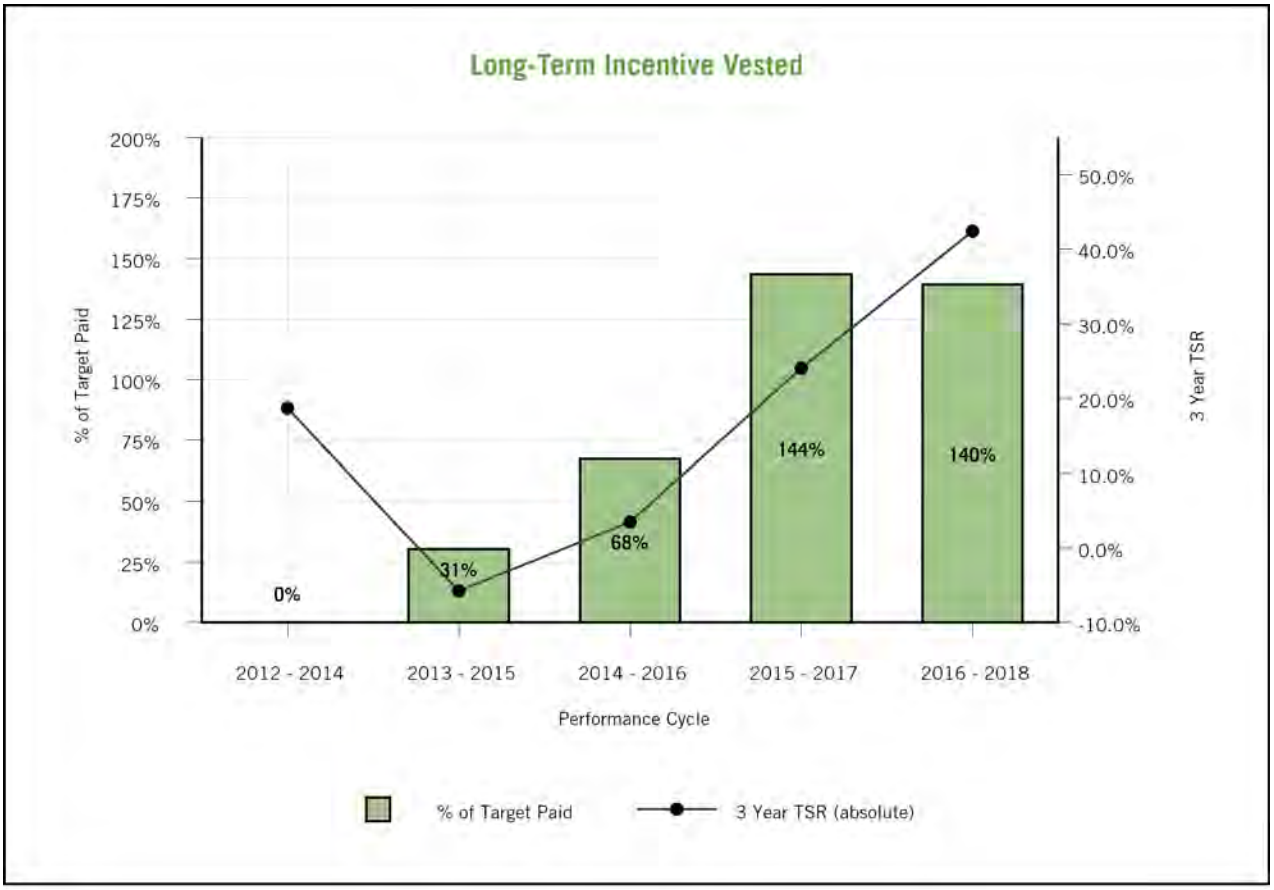
The following chart shows the percentage payout of the annual incentive target realized by our CEO with a comparison to earnings per share from continuing operations for the last five years. The chart demonstrates the alignment between our financial performance and realized annual cash incentive compensation.



* MDU Resources Group, Inc. reported 2017 earnings from continuing operations of $1.45 per share which included a non-recurring benefit of 20 cents per share attributable to the federal Tax Cuts and Jobs Act that was signed into law on December 22, 2017.

Long-Term Equity-Based Incentive Awards

Our compensation committee and the board approve grants of long-term incentives to our executives in the form of performance shares which vest into company stock plus dividend equivalents at the end of a three-year performance cycle upon achievement of established performance measures. The following chart depicts the actual vesting percentage for the last five performance cycles and demonstrates the alignment between total stockholder return (TSR) and realized long-term incentive compensation by our executives.



In their February 2018 meeting, the compensation committee and the board approved off-cycle awards to Messrs. Barney and Thiede of time-vesting restricted stock units which will vest on December 31, 2020, if the executives remain employed through the vesting date. The compensation committee believed the restricted stock unit awards incentivize Messrs. Barney and Thiede to continue their employment for the next three years and grow their respective business segments during that time.

See the “Long-Term Incentives” section within this Compensation Discussion and Analysis for further details on the company’s long-term incentive program.

With the majority of our executive officer’s compensation dependent on the achievement of performance measures set by the compensation committee, we believe there is substantial alignment between executive pay and the company’s performance.

Stockholder Advisory Vote (“Say on Pay”)

At our 2018 Annual Meeting of Stockholders, 95.9% of the votes cast on the “Say on Pay” proposal approved the compensation of our named executive officers. The compensation committee viewed the 2018 vote as an expression of the stockholders general satisfaction with the company’s executive compensation programs. The compensation committee reviewed and considered the 2018 vote on “Say on Pay” in setting compensation for 2019 by continuing to link performance-based annual and long-term incentives to company financial performance and stockholder value.

Compensation Practices

Our practices and policies ensure alignment between the interests of our stockholders and our executives as well as effective compensation governance.

What We Do
☑ Pay for Performance - Annual and long-term award incentives tied to performance measures set by the compensation committee comprise the largest portion of executive compensation.
☑ Independent Compensation Committee - All members of the compensation committee meet the independence standards under the New York Stock Exchange listing standards and the Securities and Exchange Commission rules.
☑ Independent Compensation Consultant - The compensation committee retains an independent compensation consultant to evaluate executive compensation plans and practices.
☑ Competitive Compensation - Executive compensation reflects executive performance, experience, relative value compared to other positions within the company, relationship to competitive market value compensation, business segment economic environment, and the actual performance of the overall company and the business segments.
☑ Annual Cash Incentive - Payment of annual cash incentive awards are based on business segment and overall company performance against pre-established financial measures.
☑ Long-Term Equity Incentive - The long-term performance-based equity incentive in the form of performance shares represents approximately 56% of our CEO's and approximately 37% of our other named executive officers' 2018 target compensation, which may only be earned based on achievement of established performance measures at the end of a three-year period.
☑ Annual Compensation Risk Analysis - We regularly analyze the risks related to our compensation programs and conduct an annual broad risk assessment.
☑ Stock Ownership and Retention Requirements - Executive officers are required to own, within five years of appointment or promotion, company common stock equal to a multiple of their base salary. The executive officers also must retain at least 50% of the net after-tax shares of stock vested through the long-term incentive plan for at least two years or until termination of employment.
☑ Clawback Policy - If the company's audited financial statements are restated, the compensation committee may, or shall if required, demand repayment of some or all incentives paid to our executive officers within the last three years.

What We Do Not Do
☒ Stock Options - The company does not use stock options as a form of incentive compensation.
☒ Employment Agreements - Executives do not have employment agreements entitling them to specific payments upon termination or a change of control of the company.
☒ Perquisites - Executives do not receive perquisites that materially differ from those available to employees in general.
☒ Hedge Stock - Executives and directors are not allowed to hedge company securities.
☒ Pledge Stock - Executives and directors are not allowed to pledge company securities in margin accounts or as collateral for loans.
☒ No Dividends or Dividend Equivalents on Unvested Shares - We do not provide for payment of dividends or dividend equivalents on unvested share awards.

2018 Compensation Framework

Objectives of our Compensation Program

We have a written executive compensation policy for our executive officers, including all the 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 for growth in enterprise value over the long-term;

- provide a competitive compensation package relative to industry-specific and general industry comparisons and internal equity;
- 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
- ensure that compensation programs do not encourage or reward excessive or imprudent risk taking.

Compensation Decision Process for 2018

For 2018, the compensation committee made recommendations to the board of directors regarding compensation of all executive officers, and the board of directors then approved the recommendations. The CEO's role in the process includes the assessment of executive officer performance and recommending base salaries for the executive officers other than himself. The CEO attended all compensation committee meetings but was not present during discussions of his compensation. The compensation committee established and approved base salaries and performance measures for the annual and long-term incentive compensation for 2018. They also certified the achievement of performance measures in 2017 associated with annual and long-term incentive compensation.

At least every two years, the compensation committee hires an independent consulting firm to assess and recommend competitive pay levels, including base salaries and incentive compensation, associated with executive officer positions. Typically the consulting firm conducts its analysis in even numbered years. In odd numbered years, the assessment is performed by the company's human resources department using a variety of industry specific sources. In August 2017, the company's human resources department prepared the analysis of and provided recommendations for the 2018 compensation structure.

Components of Compensation

The components of our executive officer's compensation are selected to drive financial and operational results as well as align the executive officer's interests with those of our stockholders. The components of our executive compensation include:

Component	Payments	Purpose	How Determined	How it Links to Performance
Base Salary	Assured	Provides sufficient, regularly paid income to recruit and retain executives with the knowledge, skills, and abilities necessary to successfully execute their job responsibilities.	Based on recommendation from the CEO for executives other than himself and analysis of peer company and industry compensation information.	Base salary is a means to attract and retain talented executives capable of driving success and performance.
Annual Cash Incentive	Performance Based At Risk	Provides an opportunity to earn annual incentive compensation to ensure focus on annual financial results and to be competitive from a total renumeration standpoint.	Annual cash incentives are calculated as a percentage of base salary with payout based on the achievement of performance measures established in advance by the compensation committee.	Annual incentive performance measures are tied to the achievement of financial goals aimed to drive the success of the company and the individual business segments.
Performance Shares	Performance Based At Risk	Provides an opportunity to earn long-term compensation to ensure focus on stockholder return and to be competitive from a total renumeration standpoint.	Performance share award opportunities are calculated as a percentage of base salary with vesting based on the company's achievement of financial measures established by the compensation committee as well as total stockholder return in comparison to the company's peer group over a three-year performance cycle.	Fosters ownership in company stock and aligns the executive's interests with those of stockholders in increasing stockholder value.
Restricted Stock Units	Time Vested	Provides an opportunity to earn long-term compensation to promote retention of executive talent, focus on long-term business segment growth, and to be competitive from a total renumeration standpoint.	Restricted stock unit awards are determined by the compensation committee and vest at the end of a three-year period if the executive remains employed by the company.	Fosters ownership in company stock and incentivizes executives to remain employed with the company while aligning the executive's interests with those of the stockholder in increasing stockholder value.

Allocation of Total Target Compensation for 2018

Total target compensation consists of base salary plus target annual and long-term incentive compensation. Performance-based incentive compensation, which consists of annual cash incentive and three-year performance share award opportunities, comprises the largest 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 dependent upon our performance;
- incentive compensation helps ensure focus on performance measures that are aligned with our overall strategy; and
- the interests of the named executive officers are aligned with those of stockholders by making a significant portion of their target compensation contingent upon results beneficial to stockholders.

To foster and reward long-term growth, the compensation committee generally allocates a higher percentage of total target compensation to the target long-term incentive than to the target annual incentive for our higher level executives because they are in a better position to influence long-term performance. The long-term incentive awards, if earned by achieving established measures, are paid in company common stock. These awards, combined with our stock retention requirements and our stock ownership policy, promote ownership of our stock by the executive officers. The compensation committee believes the executive officers, as stockholders, will be motivated to deliver results that build value for all stockholders over the long term.

Peer Group

The compensation committee evaluates the company's compensation plan and its performance relative to a group of peer companies in determining compensation and the vesting of long-term incentive compensation. The companies included in our peer group are evaluated every year and are selected as representatives of the industries in which we operate. The 2018 peer group includes twelve companies in regulated energy delivery businesses, and eight companies in the construction materials or construction services businesses. In determining the 2018 peer group, we removed five companies, namely Avista Corporation, National Fuel Gas Company, IES Holdings, Inc., Quanta Services, Inc., and Sterling Construction Company, Inc., due to size, industry focus, or pending merger. Companies added to the 2018 peer group were Otter Tail Corporation, Portland General Electric Company, Southwest Gas Holdings, Inc., Spire, Inc., MasTec, Inc., and Summit Materials, Inc. due to their industry focus, relative size, and geographic location. The following chart depicts the companies in our 2018 peer group.

2018 Peer Companies

Regulated Energy Delivery	Construction Materials and Services
ALLETE, Inc.	EMCOR Group, Inc.
Alliant Energy Corporation	Granite Construction Incorporated
Atmos Energy Corporation	Martin Marietta Materials, Inc.
Black Hills Corporation	MasTec, Inc.
IDACORP, Inc.	MYR Group, Inc.
Northwest Natural Gas Company	Summit Materials, Inc.
NorthWestern Corporation	U.S. Concrete, Inc.
Otter Tail Corporation	Vulcan Materials Company
Portland General Electric Company	
Southwest Gas Holdings, Inc.	
Spire Inc.	
Vectren Corporation	

2018 Compensation for Our Named Executive Officers

2018 Base Salary and Incentive Targets

At its November 2017 meeting, the compensation committee approved 2018 base salaries for the named executive officers. Mr. Goodin was not present during the portion of the meeting where the compensation committee discussed and approved the president and CEO base salary for 2018. At its February 2018 meeting, the compensation committee approved the target annual and long-term incentive opportunities for our named executive officers. In determining base salaries, target cash annual incentives, target long-term incentives, and total direct compensation for our named executive officers, the compensation committee received and considered company and individual performance, market and peer data, responsibilities, experience, tenure in position, internal equity, and input and recommendations from the CEO and human resources department. The following information relates to each named executive officer's base salary, target cash annual incentive, target long-term incentive, and total direct compensation:

David L. Goodin	2018 ($)	Compensation Component as a % of Base Salary
Base Salary	824,460	
Target Annual Incentive Opportunity	824,460	100%
Target Long-Term Performance Share Incentive Opportunity	2,061,150	250%
Target Total Potential Direct Compensation	3,710,070	

The compensation committee considered information provided in the 2016 and 2017 compensation studies showing Mr. Goodin's base salary, total cash compensation, and long-term incentives were below market levels and increased Mr. Goodin's base salary by 4% and long-term incentive target from 225% to 250% for 2018. No changes were made to Mr. Goodin's annual incentive target as a percentage of base salary.

Jason L. Vollmer	2018 ($)	Compensation Component as a % of Base Salary
Base Salary	350,000	
Target Annual Incentive Opportunity	227,500	65%
Target Long-Term Performance Share Incentive Opportunity	420,000	120%
Target Total Potential Direct Compensation	997,500	

For 2018, Mr. Vollmer's base salary remained at $350,000, which was set when he was promoted to CFO effective September 30, 2017. His annual and long-term incentive targets were set at 65% and 120% of his base salary, respectively.

David C. Barney	2018 ($)	Compensation Component as a % of Base Salary
Base Salary	455,000	
Target Annual Incentive Opportunity	341,250	75%
Target Long-Term Performance Share Incentive Opportunity	546,000	120%
Target Restricted Stock Units Opportunity	300,000	66%
Target Total Potential Direct Compensation	1,642,250	

Mr. Barney received a 6.5% increase in base salary for 2018. For 2018, the compensation committee maintained Mr. Barney's target annual incentive opportunity at 75% of his base salary but increased his long-term incentive opportunity from 90% to 120%. Mr. Barney also received a grant of 11,419 restricted stock units which vest on December 31, 2020, if he remains employed by the company.

Jeffrey S. Thiede	2018 ($)	Compensation Component as a % of Base Salary
Base Salary	455,000	
Target Annual Incentive Opportunity	341,250	75%
Target Long-Term Performance Share Incentive Opportunity	546,000	120%
Target Restricted Stock Units Opportunity	300,000	66%
Target Total Potential Direct Compensation	1,642,250	

Mr. Thiede received a 3.9% increase in his base salary for 2018. For 2018, the compensation committee maintained Mr. Thiede's target annual incentive opportunity at 75% of base salary but increased his long-term incentive opportunity from 90% to 120%. Mr. Thiede also received a grant of 11,419 restricted stock units which vest on December 31, 2020, if he remains employed by the company.

Nicole A. Kivisto	2018 ($)	Compensation Component as a % of Base Salary
Base Salary	430,000	
Target Annual Incentive Opportunity	279,500	65%
Target Long-Term Performance Share Incentive Opportunity	516,000	120%
Target Total Potential Direct Compensation	1,225,500	
Ms. Kivisto received a base salary increase of 13.8% for 2018. The compensation committee maintained her target annual incentive opportunity at 65% of base salary but increased her long-term incentive opportunity from 90% to 120% of base salary for 2018.		

Annual Incentives

Annual incentive awards are determined for business segment executives by the achievement of specific performance measures selected by the compensation committee including financial performance measures specific to each business segment and a performance measure tied to overall company earnings per share. For corporate executives, annual incentive awards are determined as the sum of a weighted percentage award payout of each business segment based upon achievement of its performance measures. Percentage award payouts for the business segments are weighted by the business segment's invested capital relative to the company's total invested capital. Through this, our business segment executives are incentivized to primarily focus on the success and performance of their business segment while keeping the overall financial success of the company in mind, whereas our corporate executives are incentivized to assist in the success and performance of all lines of business.

The compensation committee considered and selected objective financial performance measures to ensure that compensation to the executives reflects the success of their respective business segments and the company as well as value provided to our stockholders. Each business segment president's annual incentive performance measures include a corporate earnings per share performance measure representing 20% of the target award opportunity and a business segment financial performance measure representing 80% of the target award opportunity. The following annual incentive performance measures for 2018 were adopted by the compensation committee for the business segment presidents (exclusive of the MDU Resources Group, Inc. corporate executive officers) at its February 2018 meeting:

Measure	Applies to	Purpose	Measurement	Target	Weight	How Target was Selected
MDU Resources Diluted Adjusted Earnings per Share (EPS)	All Business Segment Presidents	EPS is a generally accepted accounting principle (GAAP) measurement and is a key driver of stockholder return. This goal applies to the presidents of all business segments to engage them as members of the company's management policy committee in the overall success of the company.	GAAP EPS (diluted) before discontinued operations plus earnings/losses from any operations discontinued after December 31, 2017, and adjusted to remove: - the effect on earnings at the company level of intersegment earnings eliminations; - the effect on earnings from losses on asset sales/ dispositions approved by the board; - the effect on earnings from withdrawal liabilities relating to multiemployer pension plans; and - the effect on earnings from transaction costs for completed acquisitions or mergers.	$1.35	20%	Target reflects EPS performance within the range of guidance for 2018 while also being higher than 2017 target. The target reflects an aggregation of the 2018 business unit financial goals and is higher than 2017 actual results minus the effect of the federal Tax Cuts and Jobs Act on 2017 results.
Business Segment Earnings	Electric and Natural Gas Distribution Segments President	Provides a measure of financial performance and an incentive to drive business results.	GAAP business segment earnings before discontinued operations plus earnings/losses from any operations discontinued after December 31, 2017, and adjusted to remove: - the effect on earnings from losses on asset sales/ dispositions approved by the board; and - the effect on earnings from transaction costs for completed acquisitions or mergers.	$89.1 million	80%	Target reflects the 2018 financial goal for the business segment and exceeds the segments' 2017 target and actual results.
	Pipeline and Midstream Segment President			$22.2 million	80%	Target reflects the 2018 financial goal of the business segment and exceeds the segment's 2017 target and actual results.
Business Segment Earnings Before Interest, Tax, Depreciation, and Amortization (EBITDA)	Construction Materials and Contracting Segment President	Provides a measure of financial performance common to the industries in which these segments operate.	EBITDA from continuing operations adjusted to remove: - the effect on earnings from losses on asset sales/ dispositions approved by the board; - the effect on earnings from withdrawal liabilities relating to multiemployer plans; and - the effect on earnings from transaction costs for completed acquisitions or mergers.	$197.5 million	80%	Target reflects the 2018 financial goal of the business segment, sufficient to exceed the segment's risk adjusted capital costs, incentivize growth of the business segment, and exceed 2017 actual results adjusted to remove the effect of the federal Tax Cuts and Jobs Act.
	Construction Services Segment President			$100.1 million	80%	Target reflects the 2018 financial goal of the business segment, sufficient to exceed the segment's risk adjusted capital costs, incentivize growth of the business segment, and exceed 2017 actual results.

Actual performance results are compared to target performance measures to arrive at a percent of target achieved. The percent of target achieved is translated into a payout percentage of the target award opportunity. Achievement of 100% of the performance target corresponds to a payout equal to the target annual award opportunity. Receipt of a payout requires threshold achievement of a performance measure which varies by business segment. Achievement below the threshold level of the performance measure results in no payout of the target award opportunity attributable to the measure. For the company EPS performance measure, threshold payout requires achievement of 85% of the target performance measure which results in a payout of 25% of the award opportunity attributable to the company EPS performance measure. For the electric and natural gas distribution segments, the pipeline and midstream segment, the construction materials and contracting segment, and the construction services business segment's performance measures, threshold payout requires achievement of 90%, 85%, 75%, and 65% of the target performance measures, respectively, resulting in business segment target award payouts of 50%, 25%, 25%, and 25%, respectively. Maximum payouts also vary by business segment. For the company EPS performance measure, as well as the electric and natural gas distribution segments and the pipeline and midstream segment, maximum payout of the business segment award opportunity is 200%, and for the construction materials and contracting segment and the construction services segment, payout of 250% of the business segment award opportunity is received if the percent of target performance achieved is 115% or greater. Results achieved between payout levels are calculated using linear interpolation.

2018 Annual Incentive Results

The 2018 performance measure results, percent of target achieved based on those results, and the associated payout percentages are presented below:

Business Segment	Performance Measure	Result	Percent of Performance Measure Achieved	Percent of Award Opportunity Payout	Weight	Weighted Award Opportunity Payout %
All Business Segments	Earnings per Share	$1.35	100.0 %	100.0 %	20%	20.0 %
Electric and Natural Gas Distribution	Earnings	$84.7 million	95.1 %	75.7 %	80%	60.6 %
Pipeline and Midstream	Earnings	$24.0 million	108.1 %	154.1 %	80%	123.3 %
Construction Materials and Contracting	EBITDA	$200.6 million	101.6 %	115.9 %	80%	92.7 %
Construction Services	EBITDA	$103.6 million	103.5 %	135.1 %	80%	108.1 %

For our corporate named executive officers, namely Messrs. Goodin and Vollmer, the compensation committee continued to base the payout of the annual cash incentives on the achievement of performance measures at the business segments weighted by each business segment's average invested capital relative to the company's total invested capital. The compensation committee believes this approach provides alignment between our corporate executives and business segment performance. Messrs. Goodin's and Vollmer's 2018 annual cash incentives were earned at 98.0% of the target award opportunity based on the following proportional weighted sum of the annual business segment payouts:

Business Segment	Column A Business Segment Award Opportunity Payout	Column B Percentage of Average Invested Capital	Column A x Column B
Electric and Natural Gas Distribution	80.6 %	58.5 %	47.2 %
Pipeline and Midstream	143.3 %	8.7 %	12.5 %
Construction Materials and Contracting	112.7 %	23.9 %	26.9 %
Construction Services	128.1 %	8.9 %	11.4 %
Total Payout Percentage			98.0 %

Based on the achievement of the performance targets, the named executive officers received the following 2018 annual incentive compensation:

Name	Target Annual Incentive ($)	Annual Incentive Earned: Payout as a % of Target (%)	Annual Incentive Earned: Amount ($)
David L. Goodin	824,460	98.0	807,971
Jason L. Vollmer	227,500	98.0	222,950
David C. Barney	341,250	112.7	384,589
Jeffrey S. Thiede	341,250	128.1	437,141
Nicole A. Kivisto	279,500	80.6	225,277

Long-Term Incentives

Long-term incentive compensation comprises approximately 56% of the CEO's 2018 total target direct compensation and 48% of the average of the other named executive officer's target total direct compensation. Stock earned under long-term incentive compensation is subject to our stock retention requirements. If the executive's employment is terminated during the performance period for cause at any time, or for any reason other than cause before the executive has reached age 55 and completed ten years of service, all performance shares and related dividend equivalents are forfeited. Restricted stock units are forfeited or canceled if the executive ceases to be an employee of the company or an affiliate except for employment termination due to death, disability, or change of control.

Grant of 2018-2020 Long-Term Performance Share Awards

For 2018, the compensation committee approved performance share awards which may vest at the end of a three-year period between 0% and 200% based on the achievement of three performance measures:

- Total stockholder return relative to that of the peer group companies represents 50% of the award and was selected to align the award with the company's performance relative to our peers;
- Compound annual growth rate in earnings from continuing operations before interest, taxes, depreciation, depletion, and amortization (EBITDA) represents 25% of the award which encourages strategic growth and focuses on controllable costs; and
- Compound annual growth rate in earnings from continuing operations represents 25% of the award which encourages quality earnings and continued growth of the company.

For the awards made in 2018, the compensation committee added the EBITDA and earnings growth measures to incentivize participants to focus on company growth in addition to total stockholder return during the performance period. Earnings used to calculate EBITDA growth and earnings growth will be adjusted for (i) the effect on earnings from losses on asset sales/dispositions approved by the board; (ii) the effect on earnings from withdrawal liabilities relating to multiemployer pension plans; and (iii) the effect on earnings from transaction costs for completed acquisitions or mergers.

On February 15, 2018, for the 2018-2020 performance period, the compensation committee determined the target number of performance shares for each named executive officer by multiplying the named executive officer’s 2018 base salary by a target long-term incentive percentage and then dividing by the average of the closing prices of our stock from January 1 through January 22, 2018, which was $26.27 per share. Based on this price, the board of directors, upon recommendation of the compensation committee, awarded the following target performance share opportunities to the named executive officers:

Name	Base Salary to Determine Target ($)	Target Long-Term Performance Share Incentive % of Base Salary (%)	Long-Term Performance Share Incentive Target ($)	Performance Share Opportunities (#)
David L. Goodin	824,460	250	2,061,150	78,460
Jason L. Vollmer	350,000	120	420,000	15,987
David C. Barney	455,000	120	546,000	20,784
Jeffrey S. Thiede	455,000	120	546,000	20,784
Nicole A. Kivisto	430,000	120	516,000	19,642

Restricted Stock Units Subject to Service Based Vesting

For 2018, the compensation committee also awarded 11,419 restricted stock units to each of Messrs. Barney and Thiede, which will vest on December 31, 2020, provided they remain employed until that date. The restricted stock unit awards represent $300,000 divided by the average closing stock price from January 1 through January 22, 2018 of $26.27 per share. The compensation committee believes the off-cycle restricted stock awards further incentivize both Messrs. Barney and Thiede to continue their employment with the company for the next three years while the company emphasizes the growth of their respective business segments. Dividend equivalents are credited to each restricted stock unit during the vesting period to the same extent that dividends are paid on shares of our common stock, but such dividend equivalents are paid only to the extent the underlying restricted stock unit vests based on the satisfaction of the service requirement. Dividend equivalents are paid at the time of settlement in cash.

Vesting of 2016-2018 Performance Share Awards

For the 2016-2018 performance period, the long-term incentive program consisted solely of performance shares. The performance criteria used for the 2016-2018 performance period was total stockholder return as a percentile of the total stockholder return for our peer companies. Our total stockholder return ranking over the performance period was at the 60th percentile which resulted in vesting at 140% of the target performance shares and dividend equivalents. The named executive officers received the following long-term compensation for the 2016-2018 performance period:

Name	Target Performance Shares (#)	Performance Shares Vested (#)	Dividend Equivalents ($)
David L. Goodin	98,764	138,269	321,475
Jason L. Vollmer	4,767	6,673	15,515
David C. Barney	18,920	26,488	61,585
Jeffrey S. Thiede	19,767	27,673	64,340
Nicole A. Kivisto	16,744	23,441	54,500

Stock Retention Requirement

The named executive officers must retain 50% of the net after-tax shares vested pursuant to the long-term incentive awards for at least two years from the date the vested shares are issued or the executive's termination of employment. The compensation committee may also require the executive officer to retain share awards net of taxes if the executive has not met the stock ownership requirements under the company's stock ownership policy for executives.

Other Benefits

The company provides post employment benefit plans and programs in which our named executive officers may be participants. We believe it is important to provide post-employment benefits which approximate retirement benefits paid by other employers to executives in similar positions. The compensation committee periodically reviews the benefits provided to maintain a market-based benefits package. Our named executive officers participated in the following plans during 2018 which are described below:

Plans	David L. Goodin	Jason L. Vollmer	David C. Barney	Jeffrey S. Thiede	Nicole A. Kivisto
401(k) Retirement Plan	Yes	Yes	Yes	Yes	Yes
Pension Plans	Yes	Yes	No	No	Yes
Supplemental Income Security Plan	Yes	No	Yes	No	Yes
Nonqualified Defined Contribution Plan	No	Yes	Yes	Yes	No

401(k) Retirement Plan

The named executive officers as well as all employees working a minimum of 1,000 hours per year are eligible to participate in the 401(k) plan and defer annual income up to the IRS limit. The company provides a match up to 3% depending on the employee's elected deferral rate. Contributions and the company match are invested in various funds based on the employee's election including company common stock.

In 2010, the company began offering increased company contributions to our 401(k) plan in lieu of pension plan contributions. For non-bargaining unit employees hired after 2006 or employees who were not previously participants in the pension plan, the added retirement contribution is 5% of plan eligible compensation. For non-bargaining unit employees hired prior to 2006 who were participants in the pension plan, the added retirement contributions are based on the employee's age as of December 31, 2009. The retirement contribution is 11.5% for Mr. Goodin, 9.0% for Ms. Kivisto, 7.0% for Mr. Vollmer, and 5.0% for Messrs. Barney and Thiede. These amounts may be reduced in accordance with the provisions of the 401(k) plan to ensure compliance with IRS limits.

Pension Plans

Effective in 2006, the defined benefit pension plans were closed to new non-bargaining unit employees and as of December 31, 2009, the defined benefit plans were frozen. For further details regarding the company's pension plans, please refer to the section entitled "Pension Benefits for 2018."

Supplemental Income Security Plan

We offered certain key managers and executives benefits under a nonqualified retirement plan, referred to as the Supplemental Income Security Plan (SISP). The SISP provides participants with additional retirement income and death benefits. Effective February 11, 2016, the SISP was amended to exclude new participants to the plan and freeze current benefit levels for existing participants. For further details regarding the company's SISP, please refer to the section entitled "Pension Benefits for 2018." Named executive officers participating in the SISP are Messrs. Goodin, Barney, and Ms. Kivisto.

The following table reflects our named executive officers' SISP benefits as of December 31, 2018:

	SISP Benefits	
Name	Annual Death Benefit ($)	Annual Retirement Benefit ($)
David L. Goodin	552,960	276,480
Jason L. Vollmer	n/a	n/a
David C. Barney	262,464	131,232
Jeffrey S. Thiede	n/a	n/a
Nicole A. Kivisto	96,000	48,000

Nonqualified Defined Contribution Plan

The company adopted the Nonqualified Defined Contribution Plan (NQDCP) effective January 1, 2012, to provide retirement and deferred compensation for a select group of management and other highly compensated employees. The compensation committee, upon recommendation from the CEO, determines which employees will participate in the NQDCP and the amount of contributions for any year. After satisfying a vesting requirement for each contribution, distributions will be made in accordance with the terms of the plan. For further details regarding the company's NQDCP, please refer to the section entitled "Nonqualified Deferred Compensation for 2018."

For 2018, the compensation committee selected and approved contributions of $35,000 to Mr. Vollmer, $150,000 to Mr. Barney, and $100,000 to Mr. Thiede. The contributions awarded to Messrs. Vollmer, Barney, and Thiede represent 10.00%, 32.97%, and 21.98% of their base salaries, respectively.

Employment and Severance Agreements

We currently do not have employment or severance agreements with our executives entitling them to specific payments upon termination of employment or a change of control of the company. The compensation committee generally considers providing severance benefits on a case-by-case basis. Any post-employment or change of control benefits available to our executives are addressed within our incentive and retirement plans. Please refer to the section entitled "Potential Payments upon Termination or Change of Control"

Compensation Governance

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 limits the deductibility of certain compensation to $1 million paid to certain officers as a business expense in any tax year. The federal Tax Cuts and Jobs Act (Tax Reform), signed into law in December 2017, expanded the number of individuals covered by the Section 162(m) deductibility limit and repealed the exception for performance-based compensation, effective for taxable years beginning after December 31, 2017. Incentive compensation approved by the compensation committee prior to Tax Reform for our CEO and those executive officers whose overall compensation was likely to exceed $1 million was generally structured to meet the requirements for the performance-based exception for deductibility for purposes of Section 162(m). As a result of Tax Reform, compensation paid to our covered executive officers in excess of $1 million will not be deductible, unless it qualifies for transition relief applicable to certain arrangements in place as of November 2, 2017.

The compensation committee also considers the accounting and cash flow implications of various forms of executive compensation. We expense salaries and annual incentive compensation as earned. For our equity awards, we record the accounting expense in accordance with Financial Accounting Standards Board 718, which is generally expensed over the vesting period.

Stock Ownership Requirements

Executives participating in our Long-Term Performance-Based Incentive Plan are required within five years of appointment or promotion into an executive level to own our common stock equal to a multiple of their base salary as outlined in the stock ownership policy. Stock owned through our 401(k) plan or by a spouse is considered in ownership calculations. The level of stock ownership compared to the ownership requirement is determined based on the closing sale price of our stock on the last trading day of the year and base salary at December 31 of the same year. The table shows the named executive officers' holdings as a multiple of their base salary.

Name	Ownership Policy Multiple of Base Salary within 5 Years	Actual Holdings as a Multiple of Base Salary[1]	Ownership requirement must be met by:
David L. Goodin	4X	7.7	1/1/2018
Jason L. Vollmer	3X	0.8	1/1/2023
David C. Barney	3X	2.3	1/1/2019
Jeffrey S. Thiede	3X	2.3	1/1/2019
Nicole A. Kivisto	3X	3.3	1/1/2020

[1] Includes stock awards earned net of taxes for the 2016-2018 performance period.

The compensation committee determined that Messrs. Barney and Thiede, who have not met the stock ownership requirement within the required time frame, are required to retain all stock vesting through the Long-Term Performance-Based Incentive Plan, net of taxes, until the stock ownership requirement is met.

Deferral of Annual Incentive Compensation

We provide executives the opportunity to defer receipt of earned annual incentives. If an executive chooses to defer all or part of an annual incentive, we credit the deferral with interest at a rate determined by the compensation committee. For 2018 , the compensation committee chose an interest rate of 4.28% based on an average of the Moody's U.S. Long-Term Corporate Bond Yield Average for "A" and "Baa" rated companies. The compensation committee's reasons for using this interest rate recognized incentive deferrals are a low-cost source of capital for the company and are unsecured obligations and, therefore, carry a higher risk to the executives.

Clawback

In February 2016, we amended our Long-Term Performance-Based Incentive Plan and Executive Incentive Compensation Plan sections regarding the repayment of incentive compensation due to accounting restatements, commonly referred to as a clawback policy. The compensation committee may, or shall if required, take action to recover incentive-based compensation from specific executives in the event the company is required to restate its financial statements due to material noncompliance with any financial reporting requirements under the securities laws.

Policy Regarding Hedging Stock Ownership

Our executive compensation policy prohibits executive officers, which includes our named executive 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 section entitled "Security Ownership" 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, Chair
Karen B. Fagg
William E. McCracken
Patricia L. Moss

EXECUTIVE COMPENSATION TABLES

Summary Compensation Table 2018

Name and Principal Position (a)	Year (b)	Salary ($) (c)	Stock Awards ($) (e)[1]	Non-Equity Incentive Plan Compensation ($) (g)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (h)[2]	All Other Compensation ($) (i)[3]	Total ($) (j)
David L. Goodin	2018	824,460	2,433,437	807,971	16,503	41,696	4,124,067
President and CEO	2017	792,750	1,504,546	1,377,007	342,727	40,971	4,058,001
	2016	755,000	1,441,954	1,055,490	218,301	40,246	3,510,991
Jason L. Vollmer[4]	2018	350,000	495,840	222,950	—	63,235	1,132,025
Vice President, CFO and Treasurer	2017	256,625	95,101	230,988	3,681	48,156	634,551
David C. Barney	2018	455,000	958,410	384,589	—	233,915	2,031,914
President and CEO of	2017	427,140	324,247	483,736	93,786	173,331	1,502,240
Knife River Corporation	2016	406,800	276,232	593,114	77,565	22,905	1,376,616
Jeffrey S. Thiede	2018	455,000	958,410	437,141	—	123,585	1,974,136
President and CEO of	2017	437,750	332,318	743,629	—	123,163	1,636,860
MDU Construction Services Group, Inc.	2016	425,000	288,598	489,600	—	122,708	1,325,906
Nicole A. Kivisto[5]	2018	430,000	609,197	225,277	210	34,494	1,299,178
President and CEO of Montana-Dakota Utilities Co.	2017	378,000	286,955	433,906	96,931	33,049	1,228,841

[1] Amounts in this column represent the aggregate grant date fair value of performance share award opportunities at target calculated in accordance with Financial Accounting Standards Board (FASB) generally accepted accounting principles for stock-based compensation in FASB Accounting Standards Codification Topic 718. This column was prepared assuming none of the awards were or will be forfeited. The amounts were calculated as described in Note 12 of our audited financial statements in our Annual Report on Form 10-K for the year ended December 31, 2018. For 2018, the total aggregate grant date fair value of performance share award opportunities assuming the highest level of payout would be as follows:

Name	Aggregate grant date fair value at highest payout ($)
David L. Goodin	4,866,874
Jason L. Vollmer	991,681
David C. Barney	1,603,026
Jeffrey S. Thiede	1,603,026
Nicole A. Kivisto	1,218,393

[2] Amounts shown for 2018 represent the change in the actuarial present value for the named executive officers' accumulated benefits under the pension plan, SISP, and Excess SISP, collectively referred to as the "accumulated pension change," plus above-market earnings on deferred annual incentives as of December 31, 2018.

Name	Accumulated Pension Change ($)	Above Market Interest ($)
David L. Goodin	(230,602)	16,503
Jason L. Vollmer	(3,594)	—
David C. Barney	(28,196)	—
Jeffrey S. Thiede	—	—
Nicole A. Kivisto	(98,726)	210

[3] All Other Compensation is comprised of:

Name	401(k) ($)[a]	Nonqualified Defined Contribution Plan ($)	Life Insurance Premium ($)	Matching Charitable Contributions ($)	Moving Stipend ($)[b]	Total ($)
David L. Goodin	39,875	—	621	1,200	—	41,696
Jason L. Vollmer	27,500	35,000	435	300	—	63,235
David C. Barney	22,000	150,000	565	1,200	60,150	233,915
Jeffrey S. Thiede	22,000	100,000	565	1,020	—	123,585
Nicole A. Kivisto	33,000	—	534	960	—	34,494

[a] Represents company contributions to the 401(k) plan, which includes matching contributions and retirement contributions made after the pension plans were frozen at December 31, 2009.

[b] Represents stipend for moving household goods as approved in Mr. Barney's 2012 relocation proposal.

[4] Mr. Vollmer was promoted to vice president, chief financial officer and treasurer effective September 30, 2017. He appeared as a named executive officer for the first time in 2017.

[5] Ms. Kivisto was promoted to president and chief executive officer of the electric and natural gas distribution segments effective January 9, 2015. She appeared as a named executive officer for the first time in 2017.

Grants of Plan-Based Awards in 2018

Name (a)	Grant Date (b)	Estimated Future Payouts Under Non-Equity Incentive Plan Awards Threshold ($) (c)	Target ($) (d)	Maximum ($) (e)	Estimated Future Payouts Under Equity Incentive Plan Awards Threshold (#) (f)	Target (#) (g)	Maximum (#) (h)	All other stock awards: Number of shares of stock or units # (i)	Grant Date Fair Value of Stock and Option Awards ($) (l)
David L. Goodin	2/15/2018 [1]	303,707	824,460	1,648,920					
	2/15/2018 [2]				15,692	78,460	156,920		2,433,437
Jason L. Vollmer	2/15/2018 [1]	83,804	227,500	455,000					
	2/15/2018 [2]				3,197	15,987	31,974		495,840
David C. Barney	2/15/2018 [1]	85,313	341,250	819,000					
	2/15/2018 [2]				4,156	20,784	41,568		644,616
	2/15/2018 [3]							11,419	313,794
Jeffrey S. Thiede	2/15/2018 [1]	85,313	341,250	819,000					
	2/15/2018 [2]				4,156	20,784	41,568		644,616
	2/15/2018 [3]							11,419	313,794
Nicole A. Kivisto	2/15/2018 [1]	125,775	279,500	559,000					
	2/15/2018 [2]				3,928	19,642	39,284		609,197

1 Annual incentive for 2018 granted pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan.

2 Performance shares for the 2018-2020 performance period granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

3 Time-vesting restricted stock units granted pursuant to the MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan.

Narrative Discussion Relating to the Summary Compensation Table and Grants of Plan-Based Awards Table

Annual Incentive

The compensation committee recommended the 2018 annual incentive award opportunities for our named executive officers and the board approved these opportunities at its meeting on February 15, 2018. The award opportunities at threshold, target, and maximum are reflected in columns (c), (d), and (e), respectively, of the Grants of Plan-Based Awards Table. The actual amount paid with respect to 2018 performance is reflected in column (g) of the Summary Compensation Table.

As described in the “Annual Incentives” section of the “Compensation Discussion and Analysis,” payment of annual award opportunities is dependent upon achievement of performance measures; actual payout may range from 0% to 200% of the target except for the construction materials and contracting and construction services segments which may range from 0% to 240%.

All our named executive officers were awarded their annual incentive opportunities pursuant to the MDU Resources Group, Inc. Executive Incentive Compensation Plan. Under the Executive Incentive Compensation Plan, executives who retire during the year at or after age 65 remain eligible to receive an award, but executives who terminate employment for other reasons are not eligible for an award. The compensation committee generally does not modify the performance measures; 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 measures, the compensation committee, in consultation with the CEO, may modify the performance measures. The compensation committee has full discretion to determine the extent to which goals have been achieved, the payment level, and whether to adjust payment of awards downward based upon individual performance. For further discussion of the specific 2018 incentive plan performance measures and results, see the “Annual Incentives” section in the “Compensation Discussion and Analysis.”

Long-Term Incentive

The compensation committee recommended long-term incentive award opportunities for the named executive officers in the form of performance shares, and the board approved the award opportunities at its meeting on February 15, 2018. The long-term incentive opportunities are presented as the number of performance shares at threshold, target, and maximum in columns (f), (g), and (h) of the

Grants of Plan-Based Awards Table. The value of the long-term performance-based incentive opportunities is based on the aggregate grant date fair value and is reflected in column (e) of the Summary Compensation Table and column (l) of the Grant of Plan-Based Awards Table.

Depending on the achievement of the performance measures associated with our 2018-2020 performance period, executives will receive from 0% to 200% of the target awards in February 2021. We also will pay dividend equivalents in cash on the number of shares actually vested for the performance period. The dividend equivalents will be paid in 2021 at the same time as the performance share awards are issued.

The compensation committee also awarded Messrs. Barney and Thiede each 11,419 restricted stock units on February 15, 2018, which will vest on December 31, 2020 if the officers remain employees of the company through the vesting date as reflected in column (i) of the Grants of Plan-Based Awards Table. The compensation committee believes the restricted stock unit awards will incentivize Messrs. Barney and Thiede to continue their employment with the company for the next three years and grow their respective business segments during that time. For further discussion of the specific long-term incentive plan, see the "Long-Term Incentives" section in the "Compensation Discussion and Analysis."

Nonqualified Defined Contribution Plan

The CEO recommends participants and contribution amounts to the Nonqualified Defined Contribution Plan which are approved by the compensation committee of the board of directors. The purpose of the plan is to recognize outstanding performance coupled with enhanced retention as the Nonqualified Defined Contribution Plan requires a vesting period. The amount shown in column (i) - All Other Compensation of the Summary Compensation Table includes contributions of $35,000 to Mr. Vollmer, $150,000 to Mr. Barney, and $100,000 to Mr. Thiede. For further information, see the section entitled "Nonqualified Deferred Compensation for 2018."

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	824,460	—	4,124,067	20.0 %
Jason L. Vollmer	350,000	—	1,132,025	30.9 %
David C. Barney	455,000	—	2,031,914	22.4 %
Jeffrey S. Thiede	455,000	—	1,974,136	23.0 %
Nicole A. Kivisto	430,000	—	1,299,178	33.1 %

Outstanding Equity Awards at Fiscal Year-End 2018

	Stock Awards	
Name (a)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#) (i)[1]	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($) (j)[2]
David L. Goodin	337,878	8,055,012
Jason L. Vollmer	29,433	701,683
David C. Barney	83,381	1,987,803
Jeffrey S. Thiede	85,407	2,036,103
Nicole A. Kivisto	64,934	1,548,027

1 Below is a breakdown by year of the outstanding performance share plan awards:

	2016 Award	2017 Award	2018 Award	
Performance Period End	12/31/2018	12/31/2019	12/31/2020	Total
David L. Goodin	197,528	61,890	78,460	337,878
Jason L. Vollmer	9,534	3,912	15,987	29,433
David C. Barney	37,840	13,338	32,203	83,381
Jeffrey S. Thiede	39,534	13,670	32,203	85,407
Nicole A. Kivisto	33,488	11,804	19,642	64,934

Shares for the 2016 award are shown at the maximum level (200%) based on results for the 2016-2018 performance cycle above target.

Shares for the 2017 award are shown at the target level (100%) based on results for the first two years of the 2017-2019 performance cycle between threshold and target

Shares for the 2018 award are shown at the target level (100%) based on results for the first year of the 2018-2020 performance cycle between threshold and target The number of shares under the 2018 award also includes 11,419 time-vesting restricted stock units granted to Messrs. Barney and Thiede.

2 Value based on the number of performance shares and restricted stock units reflected in column (i) multiplied by $23.84, the year-end per share closing stock price for 2018.

While for purposes of the Outstanding Equity Awards at Fiscal Year-End 2018 Table, the number of shares and value shown for the 2016-2018 performance cycle is at 200% of target, the actual results for the performance period certified by the compensation committee and settled on February 14, 2019, was 140% of target. For further information, see the “Long-Term Incentives” section of the “Compensation Discussion and Analysis”

Option Exercises and Stock Vested During 2018

Name (a)	Stock Awards: Number of Shares Acquired on Vesting (#) (d)[1]	Stock Awards: Value Realized on Vesting ($) (e)[2]
David L. Goodin	103,916	3,090,981
Jason L. Vollmer	2,751	81,829
David C. Barney	16,912	503,047
Jeffrey S. Thiede	18,198	541,300
Nicole A. Kivisto	17,616	523,988

1 Reflects performance shares for the 2015-2017 performance period ended December 31, 2017, which were settled February 15, 2018.

2 Reflects the value of vested performance shares based on the closing stock price of $27.48 per share on February 15, 2018, and the dividend equivalents paid on the vested shares.

Pension Benefits for 2018

Name (a)	Plan Name (b)	Number of Years Credited Service (#) (c)[1]	Present Value of Accumulated Benefit ($) (d)
David L. Goodin	Pension	26	1,146,362
	Basic SISP[2]	10	2,343,866
	Excess SISP[3]	26	38,870
Jason L. Vollmer	Pension	4	20,857
	Basic SISP[3]	n/a	—
	Excess SISP[3]	n/a	—
David C. Barney	Pension[3]	n/a	—
	Basic SISP[2]	10	1,449,287
	Excess SISP[3]	n/a	—
Jeffrey S. Thiede	Pension[3]	n/a	—
	Basic SISP[3]	n/a	—
	Excess SISP[3]	n/a	—
Nicole A. Kivisto	Pension	14	220,945
	Basic SISP[2]	8	424,883
	Excess SISP[3]	n/a	—

1 Years of credited service related to the pension plan reflects the years of participation in the plan as of December 31, 2009, when the pension plan was frozen. Years of credited service related to the Basic SISP reflects the years toward full vesting of the benefit which is 10 years. Years of credited service related to Excess SISP reflects the same number of credited years of services as the pension plan.

2 The present value of accumulated benefits for the Basic SISP assumes the named executive officer would be fully vested in the benefit on the benefit commencement date; therefore, no reduction was made to reflect actual vesting levels.

3 Messrs. Barney and Thiede are not eligible to participate in the pension plans. Messrs. Vollmer and Thiede do not participate in the SISP. Mr. Goodin is the only named executive officer eligible to participate in the Excess SISP.

The amounts shown for the pension plan, Basic SISP, and Excess SISP represent the actuarial present values of the executives' accumulated benefits accrued as of December 31, 2018, calculated using:

- a 3.85% discount rate for the Basic SISP and Excess SISP;
- a 4.01% discount rate for the pension plan;
- the Society of Actuaries RP-2014 Mortality Table with scale MP-2018 for post-retirement mortality; and
- no recognition of future salary increases or pre-retirement mortality.

The actuary assumed a retirement age of 60 for the pension, Basic SISP, and Excess SISP benefits and assumed retirement benefits commence at age 60 for the pension and Excess SISP and age 65 for Basic SISP benefits.

Pension Plan

The MDU Resources Group, Inc. Pension Plan for Non-Bargaining Unit Employees (pension plan) applies to employees hired before 2006 and was amended to cease benefit accruals as of December 31, 2009. The benefits under the pension plan are based on a participant's average annual salary over the 60 consecutive month period where the participant received the highest annual salary between 1999 and 2009. Benefits are paid as straight life annuities for single participants and as actuarially reduced annuities with a survivor benefit for married participants unless they choose otherwise.

Supplemental Income Security Plan

The Supplemental Income Security Plan (SISP), a defined benefit nonqualified retirement plan, is offered to select key managers and executives. SISP benefits are determined by reference to levels defined within the plan. Our compensation committee, after receiving recommendations from our CEO, determined each participant's level within the plan. On February 11, 2016, the SISP was amended to exclude new participants to the plan and freeze current benefit levels for existing participants.

Basic SISP Benefits

Basic SISP is a supplemental retirement benefit intended to augment the retirement income provided under the pension plans. The Basic SISP benefits are subject to the following ten-year vesting schedule:

- 0% vesting for less than three years of participation;
- 20% vesting for three years of participation;
- 40% vesting for four years of participation; and
- an additional 10% vesting for each additional year of participation up to 100% vesting for ten years of participation.

Participants can elect to receive the Basic SISP as:

- monthly retirement benefits only;
- monthly death benefits paid to a beneficiary only; or
- a combination of retirement and death benefits, where each benefit is reduced proportionately.

Regardless of the election, if the participant dies before the SISP retirement benefit commences, only the SISP death benefit is provided.

Excess SISP Benefits

Excess SISP is an additional retirement benefit relating to Internal Revenue Code limitations on retirement benefits provided under the pension plans. Excess SISP benefits are equal to the difference between 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 the actual benefits payable to the participant under the pension plans. Participants are only eligible for the Excess SISP benefits if the participant is fully vested under the pension plan, their employment terminates prior to age 65, and benefits under the pension plan are reduced due to limitations under the Internal Revenue Code on plan compensation.

In 2009, the SISP was amended to limit eligibility for the Excess SISP benefit. Mr. Goodin is the only named executive officer eligible for the Excess SISP benefit and must remain employed with the company until age 60 in order to receive the 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.

Both Basic and Excess SISP benefits are forfeited if the participant's employment is terminated for cause.

Nonqualified Deferred Compensation for 2018

Deferred Annual Incentive Compensation

Executives participating in the annual 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 2018 was 4.28% based on an average of the Moody's U.S. Long-Term Corporate Bond Yield Average for “A” and “Baa” rated companies. 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 earned. The amounts are paid in accordance with the participant's election in either a lump sum or in monthly installments not to exceed 120 months. In the event of a change of control, all amounts deferred would immediately become payable. For purposes of deferred annual incentive compensation, 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 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 employees. The compensation committee approves the amount of employer contributions under the Nonqualified Defined Contribution Plan and the obligations under the plan constitute an unsecured promise of the company to make such payments. The company credits contributions to plan accounts which capture the hypothetical investment experience based on the participant's elections. Contributions made prior to 2017 vest four years after each contribution in accordance with the terms of the plan. Contributions made in 2017 vest rateably over a three-year period with 1/3 vesting after the first year, an additional 1/3 after the second year, and the final 1/3 after the third year. Amounts shown as aggregate earnings in the table below for Messrs. Vollmer, Barney, and Thiede reflect the change in investment value at market rates for the hypothetical investments selected by the participants. Participants may elect to receive their vested contributions and investment earnings either in a lump sum upon separation from service with the company or in annual installments over a period of years 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.

The table below includes individual contributions from deferrals of annual incentive compensation and company contributions under the Nonqualified Defined Contribution Plan:

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	688,504	—	58,102	—	1,498,658 [1]
Jason L. Vollmer	—	35,000	(6,425)	—	56,250 [2]
David C. Barney	—	150,000	(19,556)	—	303,785 [3]
Jeffrey S. Thiede	—	100,000	(52,812)	—	627,169 [4]
Nicole A. Kivisto	—	—	740	—	17,685

1 Mr. Goodin deferred 50% of his 2017 annual incentive compensation which was $1,377,007 as reported in the Summary Compensation Table for 2017.

2 Mr. Vollmer received $35,000 under the Nonqualified Defined Contribution Plan for 2018. Mr. Vollmer's balance also includes a contribution of $22,550 for 2017. Each of these amounts are reported in column (i) of the Summary Compensation Table for its respective year, where applicable.

3 Mr. Barney received $150,000 under the Nonqualified Defined Contribution Plan for 2018. Mr. Barney's balance also includes a contribution of $150,000 for 2017. Each of these amounts are reported in column (i) of the Summary Compensation Table for its respective year.

4 Mr. Thiede received $100,000 under the Nonqualified Defined Contribution Plan for 2018. Mr. Thiede's balance also includes contributions of $100,000 for 2017, $100,000 for 2016, $150,000 for 2015, $75,000 for 2014, and $33,000 for 2013. Each of these amounts is reported in column (i) of the Summary Compensation Table in the Proxy Statement for its respective year, where applicable.

Potential Payments upon Termination or Change of Control

The Potential Payments upon Termination or Change of Control Table shows the payments and benefits our named executive officers would receive in connection with a variety of employment termination scenarios or upon a change of control. The scenarios include:

- Voluntary Termination
- Not for Cause Termination
- Death
- Disability
- Change of Control with Termination
- Change of Control without Termination.

For the named executive officers, the information assumes the terminations or the change of control occurred on December 31, 2018

The table excludes compensation and benefits our named executive officers would earn during their employment with us whether or not a termination or change of control event had occurred. The tables also do not include benefits under plans or arrangements generally available to all salaried employees and that do not discriminate in favor of the named executive officers, such as benefits under our qualified defined benefit pension plan (for employees hired before 2006), accrued vacation pay, continuation of health care benefits, and life insurance benefits. The tables also do not include Nonqualified Defined Contribution Plan or deferred annual compensation amounts which are shown and explained in the Nonqualified Deferred Compensation for 2018 Table.

Compensation

None of our named executive officers have employment or severance agreements entitling them to their base salary, some multiple of base salary or severance upon termination or change of control. Our compensation committee generally considers providing severance benefits on a case-by-case basis. Because severance payments are discretionary, no amounts are presented in the tables.

All our named executive officers were granted their 2018 annual incentive award under the Executive Incentive Compensation Plan (EICP) which has no change of control provision in regards to annual incentive compensation other than for deferred compensation. The EICP requires participants to remain employed with the company through the service year to be eligible for a payout unless otherwise determined by the compensation committee for named executive officers, or employment termination after age 65. As all our scenarios assume a termination or change in control event on December 31st, the named executives officers would be considered employed for the entire performance period; therefore, no amounts are shown for annual incentives in the tables for our named executive officers, as they would be eligible to receive their annual incentive award based on the level that performance measures were achieved for the performance period regardless of termination or change of control occurring on December 31,2018 .

All named executive officers received their performance share awards under the Long-Term Performance-Based Incentive Plan (LTIP). Upon a change of control (with or without termination), performance share awards would be deemed fully earned and vest at their target levels for the named executive officers. For this purpose, the term “change of control” is defined in the LTIP as:

- the acquisition by an individual, entity, or group of 20% or more of our outstanding common stock;
- a majority of our board of directors whose election or nomination was not approved by a majority of the incumbent 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.

For termination scenarios other than a change of control, our award agreements provide that performance share awards are forfeited if the participant’s employment terminates before the participant has reached age 55 and completed 10 years of service. If a participant’s employment is terminated other than for cause after reaching age 55 and completing 10 years of service, performance shares are prorated as follows:

- termination of employment during the first year of the performance period = shares are forfeited;
- termination of employment during the second year of the performance period = performance shares earned are prorated based on the number of months employed during the performance period; and
- termination of employment during the third year of the performance period = full amount of any performance shares earned are received.

Under the termination scenarios, Messrs. Goodin, Barney, and Thiede would receive performance shares as they have each reached age 55 and have 10 or more years of service. The number of performance shares received would be based on the following:

- 2016- 2018 performance shares would vest based on the achievement of the performance measure for the period ended December 31, 2018, which was 140%;
- 2017-2019 performance shares would be prorated at 24 out of 36 months (2/3) of the performance period and vest based on the achievement of the performance measure for the period ended December 31, 2019. For purposes of the Potential Payments upon Termination or Change of Control Table, the vesting is shown at 100%; and
- 2018- 2020 performance shares would be forfeited.

For purposes of calculating the performance share value shown in the Potential Payments upon Termination or Change of Control Table, the number of vesting shares was multiplied by the average of the high and low stock price for the last market day of the year, which was December 31, 2018. Dividend equivalents based on the number of vesting shares are also included in the amounts presented.

Neither Ms. Kivisto nor Mr. Vollmer have reached age 55; therefore, they are not eligible for vesting of performance shares in the event of their termination.

Messrs. Barney and Thiede were granted 11,419 restricted stock units in February 2018. The restricted stock units will vest on December 31, 2020 provided that Messrs. Barney and Thiede remain continuously employed by the company through December 31, 2020, except for termination due to death or disability or a change in control as defined in the LTIP. In the case of a voluntary or not for cause termination on December 31, 2018, Messrs Barney and Thiede would forfeit the restricted stock units. In the case of death or disability, the restricted stock units would vest based on the number of full months of employment completed during the grant period to the date of death or disability divided by the total number of months in the grant period. In the case of death or disability occurring on December 31, 2018, one-third of Messrs. Barney and Thiede’s restricted stock units plus dividend equivalents would vest. In the case of a change of control (with or without termination) occurring on December 31, 2018, the restricted stock units plus dividend equivalents would fully vest.

Benefits and Perquisites

Supplemental Income Security Plan

As described in the “Pension Benefits for 2018” section, the Basis SISP provides a benefit of payments commencing at age 65 and payable for 15 years. Of the named executive officers, only Messrs. Goodin, Barney, and Ms. Kivisto participate in the Basic SISP benefits. While Messrs. Goodin and Barney are 100% vested in their SISP benefit, Ms. Kivisto entered the plan in 2011 and is only 80% vested in her SISP benefit at December 31, 2018. Ms. Kivisto received a benefit level upgrade in 2014, which cliff vests on January 1, 2021. This means that if her employment terminates for any reason other than death before January 1, 2021, her benefit upgrade is forfeited.

Under all scenarios except death and change of control without termination, the payment represents the present value of the vested Basic SISP benefit as of December 31, 2018 using the monthly retirement benefit shown in the table below and a discount rate of 3.85%. In the event of death, Messrs. Goodin, Barney, and Ms. Kivisto’s beneficiaries would receive monthly death benefit payments for 15 years. The Potential Payments upon Termination or Change of Control Table shows the present value calculations of the monthly death benefit using the 3.85% discount rate.

	Monthly SISP Retirement Payment ($)	Monthly SISP Death Payment ($)
David L. Goodin	23,040	46,080
David C. Barney	10,936	21,872
Nicole A. Kivisto	5,000 *	10,000 *

* Ms. Kivisto’s calculations are based on 80% of the value shown above for voluntary, not for cause and change of control with termination scenarios. The disability scenario allows for two additional years of vesting and is calculated using 100% of the value shown above. Ms. Kivisto’s death benefit scenario is calculated using her 2014 benefit upgrade level with a monthly death benefit of $13,144.

Because the plan requires a participant to be no longer actively employed by the company in order to be eligible for payments, we do not show benefits for the change of control without termination scenario.

Disability

We provide disability benefits to some of our salaried employees equal to 60% of their base salary, subject to a salary limit of $200,000 for officers and $100,000 for other salaried employees when calculating benefits. For all eligible employees, disability payments continue until age 65 if disability occurs at or before age 60 and for five years if disability occurs between the ages of 60 and 65. Disability benefits are reduced for amounts paid as retirement benefits. The disability payments in the Potential Payments upon Termination or Change of Control Table 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. For Messrs. Goodin and Vollmer and Ms. Kivisto, who participate in the pension plan, the amount represents the present value of the disability benefit after reduction for retirement benefits using a discount rate of 4.01%. Because Mr. Goodin’s retirement benefit is greater than the disability benefit, the amount shown is zero. For Messrs. Barney and Thiede, who do not participate in the pension plan, the amount represents the present value of the disability benefit without reduction for retirement benefits using the discount rate of 3.85%, which is considered a reasonable rate for purposes of the calculation.

Potential Payments upon Termination or Change of Control Table

Executive Benefits and Payments upon Termination or Change of Control	Voluntary Termination ($)	Not for Cause Termination ($)	Death ($)	Disability ($)	Change of Control (With Termination) ($)	Change of Control (Without Termination) ($)
David L. Goodin						
Compensation:						
Performance Shares	4,615,957	4,615,957	4,615,957	4,615,957	6,067,414	6,067,414
Benefits and Perquisites:						
Basic SISP	2,343,541	2,343,541	—	2,343,541	2,343,541	—
SISP Death Benefits	—	—	6,313,609	—	—	—
Disability Benefits	—	—	—	—	—	—
Total	6,959,498	6,959,498	10,929,566	6,959,498	8,410,955	6,067,414
Jason L. Vollmer						
Compensation:						
Performance Shares	—	—	—	—	611,066	611,066
Benefits and Perquisites:						
Disability Benefits	—	—	—	893,360	—	—
Total	—	—	—	893,360	611,066	611,066
David C. Barney						
Compensation:						
Performance Shares	909,098	909,098	909,098	909,098	1,333,967	1,333,967
Restricted Stock Units	—	—	92,695	92,695	278,110	278,110
Benefits and Perquisites:						
Basic SISP	1,432,676	1,432,676	—	1,432,676	1,432,676	—
SISP Death Benefits	—	—	2,996,772	—	—	—
Disability Benefits	—	—	—	273,370	—	—
Total	2,341,774	2,341,774	3,998,565	2,707,839	3,044,753	1,612,077
Jeffrey S. Thiede						
Compensation:						
Performance Shares	945,326	945,326	945,326	945,326	1,361,390	1,361,390
Restricted Stock Units	—	—	92,695	92,695	278,110	278,110
Benefits and Perquisites:						
Disability Benefits	—	—	—	413,878	—	—
Total	945,326	945,326	1,038,021	1,451,899	1,639,500	1,639,500
Nicole A. Kivisto						
Compensation:						
Performance Shares	—	—	—	—	1,209,958	1,209,958
Benefits and Perquisites:						
Basic SISP	258,172	258,172	—	322,715	258,172	—
SISP Death Benefits	—	—	1,800,913	—	—	—
Disability Benefits	—	—	—	708,366	—	—
Total	258,172	258,172	1,800,913	1,031,081	1,468,130	1,209,958

CEO Pay Ratio Disclosure

As required by Section 953(b) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 402(u) of Regulation S-K, we are providing information regarding the relationship of the annual total compensation of David L. Goodin, our president and chief executive officer, to the annual total compensation of our median employee.

Our employee workforce fluctuates during the year largely depending on the seasonality, number, and size of construction project activity conducted by our businesses. Approximately 49.6% of our employee workforce is employed under union bargained labor contracts which define compensation and benefits for participants which may include payments made by the company associated with employee participation in union benefit and pension plans.

We identified the median employee by examining the 2018 taxable wage information for all individuals on the company's payroll records as of December 31, 2018, excluding Mr. Goodin and the employees of Sweetman Construction Company which was acquired by our Construction Materials and Contracting segment during the fourth quarter. Because of the timing of this acquisition and its integration, payroll records were not available to include in the pay ratio analysis. Sweetman Construction Company reported 232 employees which represents less than 2% of the company's employee population. All of the company's employees are located in the United States. We made no adjustments to annualize compensation for individuals employed for only part of the year. We selected taxable wages as reported to the Internal Revenue Service on Form W-2 for 2018 to identify the median employee as it includes substantially all of the compensation for our median employee and provided a reasonably efficient and economic manner for the identification of the median employee. Our median employee works for our corporate office with annual compensation consisting of wages, annual incentive and company matching, retirement replacement and profit sharing 401(k) contributions. Our median employee does not participate in the company's pension plan since our median employee joined the company in 2017, after the plan was frozen. Our median employee receives an additional 5% company match to his 401(k) plan in lieu of pension contributions.

Once identified, we categorized the median employee's compensation to correspond to the compensation components as reported in the Summary Compensation Table. For 2018, the total annual compensation of Mr. Goodin as reported in the Summary Compensation Table included in this Proxy Statement was $4,124,067 , and the total annual compensation of our median employee was $77,268. Based on this information, the 2018 ratio of annual total compensation of Mr. Goodin to the median employee was 53 to 1.

AUDIT MATTERS

ITEM 3: RATIFICATION OF THE APPOINTMENT OF DELOITTE & TOUCHE LLP AS THE COMPANY'S INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2019

The audit committee at its February 2019 meeting appointed Deloitte & Touche LLP as our independent registered public accounting firm for fiscal year 2019 . 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 2019 , 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 annual 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 the appointment of Deloitte & Touche LLP as our independent registered public accounting firm for fiscal year 2019.

Ratification of the appointment of Deloitte & Touche LLP as our independent registered public accounting firm for 2019 requires the affirmative vote of a majority of our common stock present in person or represented by proxy at the annual meeting and entitled to vote on the proposal. Abstentions will count as votes against this proposal.

Annual Evaluation and Selection of Deloitte & Touche LLP

The audit committee annually evaluates the performance of its independent registered public accounting firm, including the senior audit engagement team, and determines whether to re-engage the current independent accounting firm or consider other firms. Factors considered by the audit committee in deciding whether to retain the current independent accounting firm include:

- Deloitte & Touche LLP's capabilities considering the complexity of our business and the resulting demands placed on Deloitte & Touche LLP in terms of technical expertise and knowledge of our industry and business;
- the quality and candor of Deloitte & Touche LLP's communications with the audit committee and management;
- Deloitte & Touche LLP's independence;
- the quality and efficiency of the services provided by Deloitte & Touche LLP, including input from management on Deloitte & Touche LLP's performance and how effectively Deloitte & Touche LLP demonstrated its independent judgment, objectivity, and professional skepticism;
- external data on audit quality and performance, including recent Public Company Accounting Oversight Board reports on Deloitte & Touche LLP and its peer firms; and
- the appropriateness of Deloitte & Touche LLP's fees, tenure as our independent auditor, including the benefits of a longer tenure, and the controls and processes in place that help ensure Deloitte & Touche LLP's continued independence.

Based on this evaluation, the audit committee and the board believe that retaining Deloitte & Touche LLP to serve as our independent registered public accounting firm for the fiscal year ending December 31, 2019, is in the best interests of our company and its stockholders.

In accordance with rules applicable to mandatory partner rotation, Deloitte & Touche LLP's lead engagement partner for our audit was changed in 2017. The audit committee oversees the process for, and ultimately approves, the selection of the lead engagement partner.

Audit Fees and Non-Audit 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 2018 and 2017 :

	2018	2017
Audit Fees[1]	$ 2,657,405	$ 2,327,450
Audit-Related Fees[2]	—	46,790
Tax Fees[3]	—	17,483
All Other Fees[4]	3,150	—
Total Fees[5]	$ 2,660,555	$ 2,391,723
Ratio of Tax and All Other Fees to Audit and Audit-Related Fees	0.1 %	0.7 %

1 Audit fees for 2018 and 2017 consisted of fees for services rendered for the annual audit of our consolidated financial statements and internal control over financial reporting, statutory and regulatory audits, reviews of quarterly financial statements, and other filings with the SEC.

2 Audit-related fees for 2017 are associated with Intermountain Gas Company Investment Tax Credit procedures and supplemental schedule review for Knife River Corporation's Northwest Region.

3 Tax fees for 2017 consisted of fees for tax training for regulated operations.

4 All other fees relate to training.

5 Total fees reported above include out-of-pocket expenses related to the services provided of $330,000 for 2018 and $282,483 for 2017.

Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Registered Public Accounting Firm

The audit committee pre-approved all services Deloitte & Touche LLP performed in 2018 in accordance with the pre-approval policy and procedures the audit committee adopted in 2003. 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 SEC.

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 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 included as an exhibit thereto or may be delivered in a separate written statement.

AUDIT COMMITTEE REPORT

In connection with our financial statements for the year ended December 31, 2018 , 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. 1301, Communications with Audit Committees; and (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 above, 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, 2018 , for filing with the SEC.

Dennis W. Johnson, Chair
Mark A. Hellerstein
Edward A. Ryan
David M. Sparby
John K. Wilson

OTHER MATTERS

ITEM 4. APPROVAL OF AN AMENDMENT TO MONTANA-DAKOTA UTILITIES CO.'S RESTATED CERTI INCORPORATION

General

On January 1, 2019, we completed a holding company reorganization pursuant to Section 251(g) of the General Corporation Law of the State of Delaware (the "DGCL") to provide additional financing flexibility and further separation between our utility companies and other businesses (the "Reorganization"). As a result of the Reorganization, Montana-Dakota Utilities Co., formerly known as MDU Resources Group, Inc. ("Montana-Dakota"), became a wholly-owned subsidiary of a new public holding company (the "Company").

As required by Section 251(g) of the DGCL, Montana-Dakota's Restated Certificate of Incorporation, as amended in connection with the Reorganization (the "Montana-Dakota Charter"), provides that any act or transaction involving Montana-Dakota, other than the election or removal of directors, that requires for its adoption under the DGCL or the Montana-Dakota Charter the approval of the stockholders of Montana-Dakota will also require the approval of the Company's stockholders by the same vote as is required by the DGCL and the Montana-Dakota Charter (the "Pass-Through Provision"). Absent a provision like the Pass-Through Provision, there is no general requirement under Delaware law that stockholders of a parent entity vote on transactions involving the parent entity's wholly-owned subsidiaries.

Accordingly, the Pass-Through Provision permits stockholders of the Company, the public holding company, to have direct voting rights as to matters affecting the Company's wholly-owned subsidiary, Montana-Dakota, that would otherwise only require the approval of Montana-Dakota's sole stockholder. This is highly unusual for a public holding company and restricts the Company's flexibility to realize the desired effects of the Reorganization.

For example, the Pass-Through Provision would require Montana-Dakota to obtain approval from the Company's stockholders, in addition to obtaining the approval of Montana-Dakota's sole stockholder, prior to making amendments to the Montana-Dakota Charter. As was required by Section 251(g) of the DGCL, the Montana-Dakota Charter is substantially identical to the Company's amended and restated certificate of incorporation, as currently in effect, with the exception of the Pass-Through Provision and certain amendments that are permissible and/or required under Section 251(g) of the DGCL. However, now that the Company is the public holding company, certain amendments to the Montana-Dakota Charter are desired in order to eliminate duplicative and unnecessary provisions in the Montana-Dakota Charter, including many provisions that are not typical or relevant for a wholly-owned subsidiary.

The deletion of the Pass-Through Provision will put the Company in the same position as substantially all other public holding companies that operate through multiple subsidiaries. It is uncommon in business organizations that operate in a holding company structure for the stockholders of the holding company to have direct voting rights as to matters that affect only subsidiaries of the holding company. Obtaining consent from a public corporation's stockholders for such internal matters would add significant expense and delay and prevent the Company from achieving the flexibility and efficiency it sought to achieve by implementing the holding company structure. By removing this requirement, the Company will gain the flexibility and efficiency currently realized by nearly all other companies who operate under the same, or similar, holding company and subsidiary structure. Specifically, the removal of the Pass-Through Provision will allow Montana-Dakota to implement further amendments to the Montana-Dakota Charter to eliminate duplicative and inapplicable charter provisions that are no longer reflective of our current holding company structure. The removal of the Pass-Through Provision would also allow Montana-Dakota's sole stockholder, without a special vote of the Company's stockholders for each amendment, to adopt amendments to the Montana-Dakota Charter such as those more typically found in the charters of wholly-owned subsidiaries whose shares are not listed for trading on any stock exchange.

The board believes that the deletion of the Pass-Through Provision will provide the Company with the flexibility to manage its organization under the holding company structure more efficiently and effectively. Our board therefore seeks approval from the Company's stockholders to amend the Montana-Dakota Charter in order to remove the Pass-Through Provision.

The Pass-Through Provision that would be eliminated by the proposed amendment reads as follows:

> Any act or transaction by or involving the Corporation, other than the election or removal of directors of the Corporation, that requires for its adoption under the General Corporation Law of Delaware or this Restated Certificate of Incorporation the approval of the stockholders of the Corporation shall, in accordance with Section 251(g) of the General Corporation Law of Delaware, require, in addition, the approval of the stockholders of MDU Resources Group, Inc. (or any successor thereto by merger), by the same vote as is required by the General Corporation Law of Delaware and/or this Restated Certificate of Incorporation.

Impact on Stockholder Rights

Removing the Pass-Through Provision from the Montana-Dakota Charter would have no effect on the right of stockholders of the Company to vote on matters relating to the Company, such as elections of directors, a merger or consolidation of the Company, a sale of all or substantially all of the Company's assets, amendments to the Company's amended and restated certificate of incorporation, or any other acts or transactions requiring the approval of the Company stockholders under applicable law. If the proposed amendment is approved by the Company's stockholders and effected, then the pass-through voting requirement at Montana-Dakota would be eliminated, and the Company would no longer be required to obtain the additional approval of the Company's stockholders for acts or transactions by or involving Montana-Dakota in the manner currently required by the Pass-Through Provision.

Required Vote

Approval requires the affirmative vote of a majority of outstanding shares of our common stock. Abstentions and broker non-votes will count as votes against this proposal.

> The board of directors recommends a vote “for” the approval of the adoption of amendment of the Montana-Dakota charter to remove the pass-through provision.

ITEM 5. APPROVAL OF AMENDMENTS TO UPDATE AND MODERNIZE THE COMPANY'S AMENDED A RESTATED CERTIFICATE OF INCORPORATION, INCLUDING REMOVING THE REQUIREMENT OF AC TWO-THIRDS VOTE OF CONTINUING DIRECTORS FOR CERTAIN BOARD ACTIONS

The company's predecessor was incorporated in 1924, and its certificate of incorporation has been amended numerous times during the company's long corporate existence. The board believes the current amended and restated certificate of incorporation (the “current certificate”) contains many outdated provisions and references that are no longer necessary or consistent with the company's present situation or modern certificates of incorporation generally, including language requiring action by two-thirds of the company's “continuing directors” for certain board actions.

The board of directors has determined that it is in the best interests of the company and its stockholders to amend and restate the current certificate to update and modernize certain of its provisions, including as follows (with further discussion below):

- Removing Requirement of Action by a Two-Thirds Vote of Continuing Directors for Certain Board Actions. Revise language requiring action by two-thirds of the company's continuing directors for certain board actions and instead require action by a simple majority of the board for those actions.

- Updating Capital Stock Provisions, Including “Blank Check” Preferred Stock. Update the company's capital stock provisions, including those relating to the preferred and preference stock, to a more standard structure and formulation for “blank check” preferred stock; and remove references to certain classes and previous series of preferred and preference stock which are no longer relevant to the company.

- Modernizing Corporate Purpose and Director Powers and Duties Language. Modernize provisions relating to the corporate purpose of the company and the powers and duties of the company's board of directors to be more customary and consistent with Delaware law.

- Housekeeping Revisions. Make other immaterial, non-substantive and ministerial changes, including reorganizing and renumbering certain provisions; correcting various references to statutes, names and dates; and deleting, consolidating and updating provisions to be consistent with Delaware law.

The board of directors has approved, and recommends the company's stockholders approve, these proposed amendments to and restatement of the current certificate (as amended and restated, the “revised certificate”). A copy of the revised certificate reflecting these proposed amendments is attached as Appendix A to this Proxy Statement. Additions to and reorganization of text of our current certificate are indicated by underlining, and deletions of text from our current certificate are indicated by strike-outs.

The descriptions of these proposed amendments are summaries and are qualified in their entirety by reference to the revised certificate. If approved by our stockholders, the proposed amendments will become effective upon the filing of a revised certificate incorporating these amendments with the Secretary of State of the State of Delaware, which filing would be made promptly after the annual meeting; provided that the board may abandon such proposed filing without further action by the stockholders if the board deems it to be in the best interests of stockholders.

Removing Requirement of Action by a Two-Thirds Vote of Continuing Directors for Certain Board Actions

In 2010, the board and the company's stockholders voted to repeal certain supermajority voting provisions in the company's certificate of incorporation relating to business combinations and make other related amendments to the certificate of incorporation. At that time, the then board had reviewed the advantages and disadvantages of such supermajority requirements and had determined their removal was in line with furthering the company's goal of ensuring the company's corporate governance policies, among other things, enhanced accountability to stockholders.

Pursuant to similar considerations, the current board has determined that removing the language requiring action by two-thirds of the company's "continuing directors" for certain board actions and related language (the "continuing director supermajority provisions"), to be advisable. The board believes that removing the continuing director supermajority provisions for the board actions further described below and instead having the full board take action by majority vote provides for more equitable board decision-making and makes each director more accountable to the company and its stockholders. These changes are also consistent with current practice and preferences of many other companies, investors, and corporate governance advisors.

The board believes it desirable to amend the continuing director supermajority provisions of the current certificate as follows:

Setting the Board Size. Article THIRTEENTH, section (a) of the current certificate provides that the number of directors constituting the board shall be not less than six nor more than fifteen persons, with the exact number of directors fixed by board resolution adopted by two-thirds of the continuing directors. Article VI, section 2 of the revised certificate provides that the number of directors constituting the board shall be not less than six nor more than fifteen, with the exact number of directors fixed by board resolution adopted by a majority of the board. The board believes the revised language provides a more equitable method of setting the size of the board and makes each member more accountable to the company and its stockholders.

Filling Board Vacancies and Newly Created Directorships. Article THIRTEENTH, section (b) of the current certificate provides that vacancies of the board and newly created directorships resulting from an increase in the authorized number of directors shall be filled by a two-thirds vote of the continuing directors. Article VI, section 5 of the revised certificate provides that vacancies of the board and newly created directorships resulting from an increase in the authorized number of directors shall be filled by a majority vote of the directors. The board believes the revised language provides a more equitable method for filling vacancies and newly created directorships of the board and makes each member more accountable to the company and its stockholders.

Calling Special Meetings of Stockholders. Article SIXTEENTH of the current certificate provides, among other things, that a special meeting of stockholders of the company shall be called by the chairman, president, or the secretary of the company upon the written request of two-thirds of the continuing directors. Article VII of the revised certificate provides that a special meeting of stockholders of the company shall be called by the chairman, president, or the secretary of the company upon the written request of a majority of the board. The board believes that the revised language provides a more equitable method for the board to determine whether to request a special meeting of stockholders and makes each member more accountable to the company and its stockholders.

Related Changes. Article THIRTEENTH, sections (e) and (f) of the current certificate are removed in their entirety in the revised certificate, as they are related exclusively to defining the term "continuing director," which would no longer be used in the revised certificate.

Updating Capital Stock Provisions, Including "Blank Check" Preferred Stock

Article FOURTH of the current certificate provides for four classes of stock: common stock, preferred stock, preferred stock A, and preference stock. The company is authorized to issue a total of 502,000,000 shares of stock, which includes: 500,000,000 shares of common stock, par value $1.00 per share; 500,000 shares of preferred stock, par value $100.00 per share; 1,000,000 shares of preferred stock A, without par value; and 500,000 shares of preference stock, without par value. Article FOURTH also provides that preferred stock may be issued as either 4.50% series preferred stock or pursuant to blank check preferred stock provisions, and preferred stock A and preference stock may be issued pursuant to blank check preferred stock A or preference stock provisions, as the case may be. The current certificate's concept of "blank check" for preferred, preferred A and preference stock refers to authorized and unissued stock of a class, where the rights, preferences, powers and limitations of a series may be expressly determined by the board consistent with the provisions of Article FOURTH. In other words, the board is empowered to provide the specific terms and conditions of such series within the requirements of Article FOURTH.

In order to shorten and simplify the company's capital stock structure in the revised certificate, the board wishes to remove provisions in the current certificate relating to all prior series of preferred stock (including 4.50% series, 4.70% series and 5.10% series), the entire class of preferred stock A and the entire class and prior series (including series B preference) of preference stock. This proposed amendment removes classes and series of stock (and the related language) that are no longer relevant to the company or its capital stock structure, as the company currently has no shares (in any series) of preferred stock, preferred A stock or preference stock outstanding, having redeemed the last outstanding shares of its preferred stock in April 2017.

In the revised certificate, Article IV continues to provide the company authority to issue a total of 502,000,000 shares of stock, but instead of four classes of stock (i.e., common stock, preferred stock, preferred A stock, and preference stock), the company has two classes of stock: 500,000,000 shares of common stock, par value $1.00 per share, and 2,000,000 shares of preferred stock, par value $100.00 per share. Article IV also updates the "blank check" preferred stock provision to a more customary formulation for modern certificates of incorporation and to be more consistent with the language of the DGCL. These proposed amendments included in Article IV do not substantively change the board's current rights to issue preferred stock, including its ability to set the relative rights, preferences, powers, and limitations of a series.

Under the updated capital stock provisions provided in the revised certificate, the board maintains its flexibility to seek future financing needs through equity (including customized preferred stock) financing as conditions may require without the delay, uncertainty and expense of obtaining stockholder approval for such transactions.

Modernizing Corporate Purpose and Director Powers and Duties Language

Corporate Purpose. Article III of the revised certificate amends Article THIRD of the current certificate by retaining only its first sentence, which provides that the company's purpose is to engage in any lawful act or activity in accordance with Delaware law, and by removing the second sentence of Article THIRD, which lists non-exclusive examples of activities within the company's corporate purpose. The board believes that the revised language is a more customary formulation for modern certificates of incorporation and that it is preferable to simply state that the company may engage in any lawful act or activity, without including a specific list of its non-exclusive business activities.

Director Powers. Article NINTH of the current certificate provides a non-exclusive list of various powers conferred on the board. Article VI of the revised certificate removes such non-exclusive list and simply provides that the business and affairs of the company shall be managed by the board and that the board is empowered to exercise all such powers and do all such things (in addition to those conferred by the company's certificate of incorporation and bylaws and by statute) as may be exercised and done by the company, unless prohibited by statute or by the company's certificate of incorporation. Pursuant to similar considerations regarding the proposed amendment to the corporate purpose provision, the board believes that the revised language is a more customary formulation for modern certificates of incorporation and that it is preferable to have broad and general language regarding the powers conferred on the board, without including a specific list of non-exclusive board powers.

Director Duties. Article FOURTEENTH of the current certificate provides a non-exclusive list of factors that the board may consider when, in exercising its judgment as to what is in the best interests of the company and its stockholders, it evaluates a proposal by a party to make a tender or exchange offer for securities of the company; effect a merger, consolidation or other business combination with the company; or effect any other transaction having similar effects upon the properties, operations, or control of the company. This non-exclusive list includes "the projected social, legal and economic effects of the proposed action or transaction upon the Corporation or its Subsidiaries, its employees, suppliers, customers and others having similar relationships with the Corporation, and the communities in which the Corporation and its Subsidiaries do business." The language of Article FOURTEENTH of the current certificate is removed entirely in the revised certificate. Under Delaware law, it is the board's obligation for those transactions referenced in Article FOURTEENTH of the current certificate to act, exercising its appropriate judgment, in the best interests of the company and its stockholders. The board believes that removal of Article FOURTEENTH is preferable because the non-exclusive list includes reference to consideration of constituencies other than the company's stockholders, whose interests may conflict with, detract from, or otherwise not be in the best interests of the company and its stockholders. By eliminating Article FOURTEENTH, the board's obligations in connection with a transaction will simply be governed by Delaware law rather than any express language in the revised certificate as is the case with most every other publicly traded company.

Housekeeping Revisions

In furtherance of the board's goal of updating and modernizing the current certificate, the revised certificate includes the following housekeeping revisions:

- Removing the language of Article SEVENTH of the current certificate, which provides that the company is to have perpetual existence, as perpetual existence is already the default under Delaware law;
- Removing the language of Article EIGHTH of the current certificate, which provides that the private property of company stockholders shall not be subject to the payment of corporate debts, as such protection is already provided under Delaware law without such provision;
- Adding Article IX of the revised certificate, which consolidates into one provision the rights of the company to amend, alter, change, or repeal any provision of the company's certificate of incorporation and the rights relating to the board's and the stockholders' powers to adopt, amend, or repeal the company bylaws (including through adding language consistent with Delaware law and the board and stockholder approval standards which currently apply to the company);
- Reorganizing and renumbering certain provisions, including deleting Articles in the current certificate that had been "[RESERVED]" and reorganizing and renumbering provisions in the revised certificate under headings titled Articles I-IX (with numbered subsections thereunder); and
- Updating references to statutes, names, and dates, including correcting certain Delaware statutory references, revising language to be more gender inclusive and updating names and dates to reflect current circumstances.

Approval requires the affirmative vote of a majority of the outstanding shares of common stock. Abstentions and broker non-votes will count as votes against this proposal.

The board recommends a vote "for" this proposal for approval of the amendments to update and modernize the company's amended and restated certificate of incorporation, including removing the requirement of action by a two-thirds vote of continuing directors for certain board actions.

INFORMATION ABOUT THE ANNUAL MEETING

Who can Vote?

Stockholders of record at the close of business on March 8, 2019, are entitled to vote each share they owned on that date on each matter presented at the meeting and any adjournment(s) thereof. As of March 8, 2019, we had 196,564,951 shares of common stock outstanding entitled to one vote per share.

Distribution of our Proxy Materials using Notice and Access

We distributed proxy materials to certain of our stockholders via the Internet under the SEC's "Notice and Access" rules to reduce our costs and decrease the environmental impact of our proxy materials. Using this method of distribution, on or about March 22, 2019, we mailed a Notice Regarding the Availability of Proxy Materials (Notice) that contains basic information about our 2019 annual meeting and instructions on how to view all proxy materials, and vote electronically, on the Internet. If you received the Notice and prefer to receive a paper copy of the proxy materials, follow the instructions in the Notice for making this request and the materials will be sent promptly to you via the preferred method. Stockholders who do not receive the Notice will receive a paper copy of our proxy materials, which will be sent on or about March 28, 2019.

How to Vote

You are encouraged to vote in advance of the meeting using one of the following voting methods, even if you are planning to attend the 2019 Annual Meeting of Stockholders.

Registered Stockholders: Stockholders of record who hold their shares directly with our stock registrar can vote any one of four ways:

Via the Internet: Go to the website shown on the Notice or Proxy Card, if you received one, and follow the instructions.

By Telephone:Call the telephone number shown on the Notice or Proxy Card, if you received one, and follow the instructions given by the voice prompts.

Voting via the Internet or by telephone authorizes the named proxies to vote your shares in the same manner as if you marked, signed, dated, and returned a Proxy Card by mail. Your voting instructions may be transmitted up until 11:59 p.m. Eastern Time on May 6, 2019.

By Mail: If you received paper copies of the Proxy Statement, Annual Report, and Proxy Card, mark, sign, date, and return the Proxy Card in the postage-paid envelope provided.

In Person: Attend the annual meeting, or send a personal representative with an appropriate proxy, to vote by ballot at the meeting.

Beneficial Stockholders: Stockholders whose shares are held beneficially in the name of a bank, broker, or other holder of record (sometimes referred to as holding shares "in street name"), will receive voting instructions from said bank, broker, or other holder of record.If you wish to vote in person at the meeting, you must obtain a legal proxy from your bank, broker, or other holder of record of your shares and present it at the meeting.

See discussion below regarding the MDU Resources Group, Inc. 401(k) Plan for voting instructions for shares held under our 401(k) plan.

Revoking Your Proxy or Changing Your Vote

You may change your vote at any time before the proxy is exercised.

Registered Stockholders:

- If you voted by mail: you may revoke your proxy by executing and delivering a timely and valid later dated proxy, by voting by ballot at the meeting, or by giving written notice of revocation to the corporate secretary.
- If you voted via the Internet or by telephone: you may change your vote with a timely and valid later Internet or telephone vote, as the case may be, or by voting by ballot at the meeting.
- Attendance at the meeting will not have the effect of revoking a proxy unless (1) you give proper written notice of revocation to the corporate secretary before the proxy is exercised, or (2) you vote by ballot at the meeting.

Beneficial Stockholders:Follow the specific directions provided by your bank, broker, or other holder of record to change or revoke any voting instructions you have already provided. Alternatively, you may vote your shares by ballot at the meeting if you obtain a legal proxy from your bank, broker, or other holder of record and present it at the meeting.

Discretionary Voting Authority

If you complete and submit your proxy voting instructions, the individuals named as proxies will follow your instructions. If you are a stockholder of record and you submit proxy voting instructions but do not direct how to vote on each item, the individuals named as proxies will vote as the board recommends on each proposal. The individuals named as proxies will vote on any other matters properly presented at the annual meeting in accordance with their discretion. Our bylaws set forth requirements for advance notice of any nominations or agenda items to be brought up for voting at the annual meeting, and we have not received timely notice of any such matters, other than the items from the board of directors described in this Proxy Statement.

Voting Standards

A majority of outstanding shares of stock entitled to vote must be present in person or represented by proxy to hold the meeting. Abstentions and broker non-votes are counted for purposes of determining whether a quorum is present at the annual meeting.

If you are a beneficial holder and do not provide specific voting instruction to your broker, the organization that holds your shares will not be authorized to vote your shares, which would result in broker non-votes, on proposals other than the ratification of the selection of our independent registered public accounting firm for 2019.

The following chart describes the proposals to be considered at the annual meeting, the vote required to elect directors and to adopt each other proposal, and the manner in which votes will be counted:

Item No.	Proposal	Voting Options	Vote Required to Adopt the Proposal	Effect of Abstentions	Effect of "Broker Non-Votes"
1	Election of Directors	For, against, or abstain on each nominee	A nominee for director will be elected if the votes cast for such nominee exceed the votes cast against such nominee.	No effect	No effect
2	Advisory Vote to Approve the Compensation Paid to the Company's Named Executive Officers	For, against, or abstain	The affirmative vote of a majority of the shares of common stock represented at the annual meeting and entitled to vote thereon	Same effect as votes against	No effect
3	Ratification of the Appointment of Deloitte & Touche LLP as the Company's Independent Registered Public Accounting Firm for 2018	For, against, or abstain	The affirmative vote of a majority of the shares of common stock represented at the annual meeting and entitled to vote thereon	Same effect as votes against	Brokers have discretion to vote
4	Approval of an Amendment to Montana-Dakota Utilities Co.'s Restated Certificate of Incorporation	For, against, or abstain	The affirmative vote of a majority of the outstanding shares of common stock	Same effect as votes against	Same effect as votes against
5	Approval of Amendments to Update and Modernize the Company's Amended and Restated Certificate of Incorporation	For, against, or abstain	The affirmative vote of a majority of the outstanding shares of common stock	Same effect as votes against	Same effect as votes against

Proxy Solicitation

The board of directors is furnishing proxy materials to solicit proxies for use at the Annual Meeting of Stockholders on May 7, 2019, and any adjournment(s) thereof. Proxies are solicited 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 $8,500 plus out-of-pocket expenses. We will pay the cost of soliciting proxies and will reimburse brokers and others for forwarding proxy materials to stockholders.

Electronic Delivery of Proxy Statement and Annual Report Documents

For stockholders receiving proxy materials by mail, you can elect to receive an email in the future that will provide electronic links to these documents. Opting to receive your proxy materials online will save the company the cost of producing and mailing documents to your home or business and will also give you an electronic link to the proxy voting site.

- Registered Stockholders: If you vote on the Internet, simply follow the prompts for enrolling in the electronic proxy delivery service. You may also enroll in the electronic proxy delivery service at any time in the future by going directly to http://enroll.icsdelivery.com/mdu to request electronic delivery. You may revoke an electronic delivery election at this site at any time.
- Beneficial Stockholders: If you hold your shares in a brokerage account, you may also have the opportunity to receive copies of the proxy materials electronically. You may enroll in the electronic proxy delivery service at any time by going directly to http://enroll.icsdelivery.com/mdu to request electronic delivery. You may also revoke an electronic delivery election at this site at any time. In addition, you may also check the information provided in the proxy materials mailed to you by your bank or broker regarding the availability of this service or contact your bank or broker to request electronic delivery.

Householding of Proxy Materials

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 will promptly deliver, 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.

MDU Resources Group, Inc. 401(k) Plan

This Proxy Statement is being used to solicit voting instructions from participants in the MDU Resources Group, Inc. 401(k) Plan with respect to shares of our common stock that are held by the trustee of the plan for the benefit of plan participants. If you are a plan participant and also own other shares as a registered stockholder or beneficial owner, you will separately receive a Notice or proxy materials to vote those other shares you hold outside of the MDU Resources Group, Inc. 401(k) Plan. If you are a plan participant, you must instruct the plan trustee to vote your shares by utilizing one of the methods described on the voting instruction form that you receive in connection with shares held in the plan. If you do not give voting instructions, the trustee generally will vote the shares allocated to your personal account in accordance with the recommendations of the board of directors. Your voting instructions may be transmitted up until 11:59 p.m. Eastern Time on May 2, 2019.

Annual Meeting Admission and Guidelines

Admission: All stockholders as of the record date of March 8, 2019, are cordially invited and urged to attend the annual meeting. You must request an admission ticket to attend. If you are a stockholder of record and plan to attend the meeting, please contact MDU Resources by email at CorporateSecretary@mduresources.com or by telephone at 701-530-1010 to request an admission ticket. A ticket will be sent to you by mail.

If your shares are held beneficially in the name of a bank, broker, or other holder of record, and you plan to attend the annual meeting, you will need to submit a written request for an admission ticket by mail to: Investor Relations, MDU Resources Group, Inc., P.O. Box 5650, Bismarck, ND 58506 or email at CorporateSecretary@mduresources.com. The request must include proof of stock ownership as of March 8, 2019, such as a bank or brokerage firm account statement or a legal proxy from the bank, broker, or other holder of record confirming ownership. A ticket will be sent to you by mail.

Requests for admission tickets must be received no later than May 1, 2019. You must present your admission ticket and state-issued photo identification, such as a driver's license, to gain admittance to the meeting.

Guidelines: The business of the meeting will follow as set forth in the agenda which you will receive at the meeting entrance. The use of cameras or sound recording equipment is prohibited, except by the media or those employed by the company to provide a record of the proceedings. The use of cell phones and other personal communication devices is also prohibited during the meeting. All devices must be turned off or muted. No firearms or weapons, banners, packages, or signs will be allowed in the meeting room. MDU Resources Group, Inc. reserves the right to inspect all items, including handbags and briefcases, that enter the meeting room.

Conduct of the Meeting

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 proxy to vote or act on such matters in their discretion.

Stockholder Proposals, Director Nominations, and Other Items of Business for 2020 Annual Meeting

Stockholder Proposals for Inclusion in Next Year's Proxy Statement. To be included in the proxy materials for our 2020 annual meeting, a stockholder proposal must be received by the corporate secretary no later than November 23, 2019, unless the date of the 2020 annual meeting is more than 30 days before or after May 7, 2020, in which case the proposal must be received a reasonable time before we begin to print and mail our proxy materials. The proposal must also comply with all applicable requirements of Rule 14a-18 under the Securities Exchange Act of 1934.

Director Nominations From Stockholders for Inclusion in Next Year's Proxy Statement. If a stockholder or group of stockholders wishes to nominate one or more director candidates to be included in our proxy statement for the 2020 annual meeting through our proxy access bylaw provision, we must receive proper written notice of the nomination not later than 120 or earlier than 150 days before the anniversary date that the definitive proxy statement was first released to stockholders in connection with the annual meeting, or between October 24, 2019 and November 23, 2019. In the event that the 2020 annual meeting is more than 30 days before or after May 7, 2020, the notice must be delivered no earlier than the 150th day prior to such meeting and no later than the 120th day prior to such meeting or the 10th day following the date on which public announcement of the meeting date is first made. In addition, the nomination must otherwise comply with the requirements in our bylaws. The requirements of such notice can be found in our bylaws, a copy of which is on our website, at www.mdu.com/governance.

Director Nominations and Other Stockholder Proposals Raised From the Floor at the 2020 Annual Meeting of Stockholders. Under our bylaws, if a stockholder intends to nominate a person as a director, or present other items of business at an annual meeting, the stockholder must provide written notice of the director nomination or stockholder proposal within 90 to 120 days prior to the anniversary of the most recent annual meeting. Notice of director nominations or stockholder proposals for our 2020 annual meeting must be received between January 8, 2020 and February 7, 2020, and meet all the requirements and contain all the information, including the completed questionnaire for director nominations, provided by our bylaws. The requirements for such notice can be found in our bylaws, a copy of which is on our website, at www.mdu.com/governance.

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, 2018, which is required to be filed with the SEC. 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, North Dakota 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,

Daniel S. Kuntz
Secretary
March 22, 2019

APPENDIX A.

AMENDED AND RESTATED CERTIFICATE OF INCORPORATION
OF
~~MDUR NEWCO~~MDU RESOURCES GROUP, INC.

~~MDUR NEWCO~~MDU RESOURCES GROUP, INC., a corporation organized and existing under the laws of the State of Delaware, hereby certifies as follows:

1. The ~~original certificate of incorporation of~~ present name of the corporation is MDU RESOURCES GROUP, INC. (the “Corporation”).

2. The Corporation was incorporated under the name “MDUR Newco, Inc~~. was filed~~” by the filing of its original Certificate of Incorporation with the Office of the Secretary of State of the State of Delaware on September 21, ~~2018 (~~2018, which was amended by the filing of its Amended and Restated Certificate of Incorporation with the Office of the Secretary of State of the State of Delaware effective as of January 1, 2019 (as amended, the “Original Certificate of Incorporation”).

~~2. MDUR Newco, Inc.~~3. The Corporation is filing this ~~a~~Amended and ~~r~~Restated ~~c~~Certificate of ~~i~~Incorporation (the “Certificate of Incorporation”), which restates, integrates and further amends the provisions of the Original Certificate of Incorporation, and which was duly adopted in accordance with Sections ~~242, 245 and 228 (by written consent of the sole stockholder of MDUR Newco, Inc.)~~228, 242 and 245 of the General Corporation Law of the State of Delaware.

~~3.~~4. The text of the Original Certificate of Incorporation is hereby amended and restated in its entirety by this Certificate of Incorporation, effective as of ~~12:02~~ [_____] [a/p].m. Eastern Standard Time on ~~January 1,~~ [______], 2019, as to read in full as follows:

ARTICLE I

NAME

~~FIRST.~~ The name of this Corporation is MDU RESOURCES GROUP, INC. (the “Corporation”).

ARTICLE II

REGISTERED OFFICE AND AGENT

~~SECOND~~ The registered office of the Corporation in the State of Delaware is located at 1209 Orange Street, Wilmington, New Castle County, Delaware 19801. The name of its registered agent at such address is The Corporation Trust Company.

ARTICLE III

CORPORATE PURPOSE

~~THIRD.~~ The purpose of the Corporation is to engage in any lawful act or activity for which corporations may be organized under the General Corporation Law of the State of Delaware. ~~Included within this purpose, without limiting the generality of the foregoing sentence is (1) to own and operate electric and gas public utility systems and (2) to transact business as a multidimensional natural resource company~~

ARTICLE IV

CAPITAL STOCK

(1) Authorized Shares.

~~The Corporation shall have and exercise all the powers conferred upon corporations by the General Corporation Law of Delaware.~~

~~FOURTH~~ The total number of shares of stock which the Corporation shall have authority to issue is Five Hundred Two Million (502,000,000) divided into ~~four~~two classes, namely, Preferred Stock~~, Preferred Stock A, Preference Stock,~~ and Common Stock. The total number of shares of such Preferred Stock authorized is ~~Five Hundred Thousand (500,000~~ Two Million (2,000,000) shares of the par value of One Hundred Dollars ($100) per share (hereinafter called the "Preferred ~~Stock") amounting in the aggregate to Fifty Million Dollars ($50,000,000). The total number of shares of such Preferred Stock A authorized is One Million (1,000,000) shares without par value (hereinafter called the "Preferred Stock A"). The total number of shares of such Preference Stock authorized is Five Hundred Thousand (500,000) shares without par value (hereinafter called the "Preference~~ Stock"). The total number of shares of such Common Stock authorized is Five Hundred Million (500,000,000) of the par value of One and no/100 Dollars ($1.00) per share (hereinafter called the "Common Stock") ~~, amounting in the aggregate to Five Hundred Million Dollars ($500,000,000).~~

~~The Preferred Stock and the Preferred Stock A shall rank equally with no preference or priority of the Preferred Stock over the Preferred Stock A or of the Preferred Stock A over the Preferred Stock with respect to earnings, and assets upon liquidation, dissolution or winding up of the Corporation, and the Preferred Stock and the Preferred Stock A shall be senior to the Preference Stock with respect to earnings, and assets upon liquidation, dissolution or winding up of the Corporation, and the Preference Stock in turn shall be senior to the Common Stock with respect thereto.~~

~~The description of such classes of stock, and the designations and the powers, preferences and rights and the qualifications, limitations or restrictions thereof are as follows:~~

~~1.~~ (2) Preferred Stock The Preferred Stock may be issued ~~from time to time either (a) as Preferred Stock of a series to be designated 4.50% Series Preferred Stock, or (b) if so determined~~ from time to time by resolution or resolutions adopted by the Board of Directors either in whole or in part as one or more other series, each series to be appropriately designated by distinguishing number, letter or title prior to the issue of any shares thereof. ~~One Hundred Thousand (100,000) shares of the Preferred Stock are hereby designated as 4.50% Series Preferred Stock. The number of shares of the Preferred Stock so designated as 4.50% Series Preferred Stock may be increased (but not above the number of shares then authorized) or decreased (but not below the number of shares thereof then outstanding) by a~~ The description and terms of the Preferred Stock of any series shall be fixed and determined by the Board of Directors at the time of the authorization of the issue of the original shares of each such series, including such voting powers, full or limited, or no voting powers, and such designations, preferences, and relative, participating, optional, or other rights and such qualifications, limitations, or restrictions thereof, as shall be stated and expressed in the resolution or resolutions adopted by the Board of Directors ~~in the same manner as the Board may by resolution create other series of the~~ providing for the issuance of such shares and as may be permitted by the General Corporation Law of the State of Delaware. The Board of Directors is also expressly authorized to increase or decrease the number of shares of any series of Preferred Stock subsequent to the issuance of shares of that series of Preferred Stock, but not below the number of shares of such series of Preferred Stock then outstanding. In case the number of shares of any series of Preferred Stock shall be decreased in accordance with the foregoing sentence, the shares constituting such decrease shall resume the status that they had prior to the adoption of the resolution originally fixing the number of shares of such series of Preferred Stock. The number of authorized shares of Preferred Stock may be increased or decreased (but not below the number of shares thereof then outstanding) by the affirmative vote of the holders of a majority of the voting power of the Corporation's outstanding capital stock entitled to vote thereon, without a separate vote of the holders of the Preferred Stock, or of any series thereof, unless a vote of any such holders is required pursuant to the terms of any certificate of designation filed with respect to any series of Preferred Stock.

~~2. The Preferred Stock of all series shall be of the same class and of equal rank and shall be identical in all respects except that~~

(3) Common StockThe preferences, limitations, voting powers and relative rights of the Common Stock (subject to the preferences and rights of the Preferred Stock as determined by the Board of Directors pursuant to Paragraph (2) of this Article IV) are as follows:

(a) ~~the maximum dividend rate of the 4.50% Series Preferred Stock shall be four and fifty hundredths per cent (4.50%) per annum, and the maximum dividend rate of the Preferred Stock of each other series shall be such rate as shall have been fixed and determined by the Board of Directors to accrue in respect of the shares of stock of each such other series from a date to be determined as hereinafter provided;~~Voting Rights. Except as otherwise expressly provided in this Certificate of Incorporation or required by applicable law, each holder of Common Stock shall be entitled to one vote for each share of Common Stock held as of the applicable record date on any matter that is submitted to a vote of the stockholders of this Corporation (including, without limitation, any matter voted on at a stockholders' meeting).

(b) ~~the amount per share which the Preferred Stock shall be entitled to receive as a premium in case of the redemption thereof shall be Five Dollars ($5.00) per share in the case of the 4.50% Series Preferred Stock, and in the case of each other series of the Preferred Stock shall be such amount, if any, as shall have been fixed and determined by the Board of Directors~~;

~~(c) a sinking fund or other retirement obligation may be provided for each series of the Preferred Stock, other than the 4.50% Series Preferred Stock, at such rate and on such terms as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series~~;

~~(d) the shares of each series of the Preferred Stock, other than the 4.50% Series Preferred Stock, may be made convertible into, or exchangeable for, shares of any other class or classes, or of any other series of the same or of any other class or classes, of stock of the Corporation, at such price or prices, or at such rates of exchange and with such adjustments as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series; and~~

~~(e) the shares of each series of the Preferred Stock, other than the 4.50% Series Preferred Stock, shall possess such voting power, in addition to that provided for in paragraph 13, as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series~~.

~~The description and terms of the Preferred Stock of each series in the foregoing particulars (except as in this section fixed and determined in respect of the 4.50% Series Preferred Stock) shall be fixed and determined by the Board of Directors at the time of the authorization of the issue of the original shares of each such other series. All shares of each series shall be alike in every particular~~.

~~3. The Preferred Stock A may be issued from time to time by resolution or resolutions adopted by the Board of Directors, either in whole or in part as one or more series, each series to be appropriately designated by distinguishing number, letter or title prior to the issue of any shares thereof.~~

~~4. The Preferred Stock A of all series shall be of the same class and of equal rank and shall be identical in all respects except that~~

~~(a) the maximum dividend rate of the Preferred Stock A of each series shall be such rate as shall have been fixed and determined by the Board of Directors to accrue in respect of the shares of stock of each such series from a date to be determined as hereinafter provided~~;

~~(b) the terms and conditions on which the shares of each series may be redeemed and in the amount or amounts per share which the Preferred Stock A of each series shall be entitled to receive in case of the redemption thereof shall be such as shall have been fixed and determined by the Board of Directors for each such series~~;

~~(c) the amount per share which the Preferred Stock A of each series shall be entitled to receive in the event of any liquidation, dissolution or winding up of this Corporation, whether voluntary or involuntary, shall be such amount as shall have been fixed and determined by the Board of Directors for such purpose for each such series~~;

~~(d) a sinking fund or other retirement obligation may be provided for any or all series of the Preferred Stock A, at such rate and on such terms as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series~~;

~~(e) the shares of any or all series of the Preferred Stock A may be made convertible into, or exchangeable for, shares of any other class or classes, or of any other series of the same~~ or ~~of any other class or classes, of stock of the Corporation, at such price or prices, or at such rates of exchange and with such adjustments as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series; and~~

~~(f) the shares of each series of the Preferred Stock A shall possess such voting power, in addition to that provided for in paragraph 13, as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series~~.

~~The description and terms of the Preferred Stock A of each series in the foregoing particulars and the number of shares constituting each series shall be fixed and determined by the Board of Directors at the time of the authorization of the issue of the original shares of each such series. All shares of each series shall be alike in every particular.~~

~~5. The Preference Stock may be issued from time to time by resolution or resolutions adopted by the Board of Directors, either in whole or in part as one or more series, each series to be appropriately designated by distinguishing number, letter or title prior to the issue of any shares thereof.~~

~~6. The Preference Stock of all series shall be of the same class and of equal rank and shall be identical in all respects except that~~

~~(a) the maximum dividend rate of the Preference Stock of each series shall be such rate as shall have been fixed and determined by the Board of Directors to accrue in respect of the shares of stock of each such series from a date to be determined as hereinafter provided~~;

~~(b) the terms and conditions on which the shares of each series may be redeemed and the and the amount or amounts per share which the Preference Stock of each series shall be entitled to receive in case of the redemption thereof shall be such as shall have been fixed and determined by the Board of Directors for each such series~~;

~~(c) the amount per share which the Preference Stock of each series shall be entitled to receive in the event of any liquidation, dissolution or winding up of this Corporation, whether voluntary or involuntary, shall be such amount as shall have been fixed and determined by the Board of Directors for such purpose for each such series~~;

~~(d) a sinking fund or other retirement obligation may be provided for any or all series of the Preference Stock, at such rate and on such terms as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series; and~~

~~(e) the shares of any or all series of the Preference Stock may be made convertible into, or exchangeable for, shares of the Common Stock, at such price or prices, or at such rates of exchange and with such adjustments as shall have been fixed and determined by the Board of Directors in respect of the shares of stock of each such series~~.

~~The description and terms of the Preference Stock of each series in the foregoing particulars and the number of shares constituting each series shall be fixed and determined by the Board of Directors at the time of the authorization of the issue of the original shares of each such series. All shares of each series shall be alike in every particular.~~

~~7. In preference to the Preference Stock and the Common Stock, out of the surplus or net profits of this Corporation, as and when declared by the Board of Directors, the holders of the 4.50% Series Preferred Stock shall be entitled to receive dividends at but not exceeding the maximum dividend rate herein fixed and determined, and the holders of the other series of Preferred Stock and all series of the Preferred Stock A shall be entitled to receive dividends, in preference to the Preference Stock and the Common Stock, out of the surplus or net profits of this Corporation, as and when declared by the Board of Directors, at but not exceeding the maximum dividend rates fixed and determined by the Board of Directors and expressed in the certificates therefor, payable quarterly on January 1st, April 1st, July 1st, and October 1st in each year, before any dividends shall be declared or paid upon or set apart for the Preference Stock or the Common Stock and before any sum shall be paid or set apart for the purchase or redemption of any series of the Preferred Stock, the Preferred Stock A or the Preference Stock, or the Common Stock. Such dividends on the Preferred Stock shall be cumulative from such date or dates as the Board of Directors shall fix at the time of issue thereof, or if no such date or dates shall be fixed, then from the respective dates of issue thereof, so that if in any dividend period or periods full cumulative dividends, at the maximum rates fixed and determined therefor, accrued on all outstanding shares of Preferred Stock and Preferred Stock A for all past dividend periods and for the then current dividend period, shall not have been paid, the~~

~~deficiency shall be declared and paid or set apart for payment before any dividends shall be declared or paid upon or set apart for the Preference Stock or for the Common Stock and before any sum shall be paid or set apart for the purchase or redemption of any series of the Preferred Stock, the Preferred Stock A or the Preference Stock, or the Common Stock~~.

~~If at any time Preferred Stock or Preferred Stock A of more than one series shall be outstanding, any dividends paid upon the Preferred Stock or the Preferred Stock A in an amount less than full cumulative dividends accrued or in arrears upon all the Preferred Stock and the Preferred Stock A outstanding shall be divided among the outstanding series of the Preferred Stock and the Preferred Stock A in proportion to the aggregate amounts which would be distributable to each series of the Preferred Stock and the Preferred Stock A if full cumulative dividends were at said time to be declared and paid thereon.~~

~~8. Subject to the prior rights and preferences of the Preferred Stock and the Preferred Stock A hereinbefore set forth, out of the surplus or net profits of this Corporation remaining after full cumulative dividends as aforesaid upon all series of the Preferred Stock and the Preferred Stock A then outstanding have been paid for all past dividend periods and after full cumulative dividends upon all series of the Preferred Stock and the Preferred Stock A for the current dividend period have been declared and paid or set apart for payment, then, as and when declared by the Board of Directors, the holders of the Preference Stock of all series shall be entitled to receive dividends at but not exceeding the maximum dividend rates fixed and determined by the Board of Directors and expressed in the resolution or resolutions authorizing the creation and issuance of each such series, payable quarterly on January 1st, April 1st, July 1st, and October 1st in each year, before any dividends shall be declared or paid upon or set apart for the Common Stock and before any sum shall be paid or set apart for the purchase or redemption of the Preference Stock of any series or the Common Stock. Such dividends on the Preference Stock shall be cumulative from such date or dates as the Board of Directors shall fix at the time of issue thereof, or if no such date or dates shall be fixed, then from the respective dates of issue thereof, so that if in any dividend period or periods full cumulative dividends, at the maximum rates fixed and determined therefor, accrued on all outstanding shares of Preference Stock for all past dividend periods and for the then current dividend period, shall not have been paid, the deficiency shall be declared and paid or set apart for payment before any dividends shall be declared or paid upon or set apart for the Common Stock and before any sum shall be paid or set apart for the purchase or redemption of the Preference Stock of any series or the Common Stock~~.

~~If at any time the Preference Stock of more than one series shall be outstanding, any dividends paid upon the Preference Stock in an amount less than full cumulative dividends accrued or in arrears upon all the Preference Stock outstanding shall be divided among the outstanding series of Preference Stock in proportion to the aggregate amounts which would be distributable to the Preference Stock of each series if full cumulative dividends were at said time to be declared and paid thereon~~.

~~9. Subject to the prior rights and preferences of the Preferred Stock, the Preferred Stock A and the Preference Stock hereinbefore set forth, out of any surplus or net profits of this Corporation remaining after full cumulative dividends as aforesaid upon all series of the Preferred Stock, the Preferred Stock A and the Preference Stock then outstanding have been paid for all past dividend periods and after full cumulative dividends upon all series of the Preferred Stock, the Preferred Stock A and the Preference Stock for the current dividend period have been declared and paid or set apart for payment and after making such provision, if any, as the Board of Directors may deem necessary for working capital, then and not otherwise, dividends may be declared and paid upon the Common Stock, to the exclusion of the holders of the Preferred Stock, the Preferred Stock A and the Preference Stock, and no holder of any series of the Preferred Stock, the Preferred Stock A or the Preference Stock shall be entitled to receive or shall receive dividends in excess of the maximum dividend rates herein set forth or fixed in the certificates therefor or in the resolution~~

~~or resolutions authorizing the creation and issuance of each such series~~.

~~The right to receive any dividends which may be declared payable in stock of any class is vested in the holders of the Common Stock exclusively, but no such dividends shall be declared in any dividend period unless full cumulative dividends upon all series of the Preferred Stock, the Preferred Stock A and the Preference Stock then outstanding shall have been paid for all past dividend periods and shall have been declared and paid or set apart for payment for the current dividend period.~~

~~10. All series of the Preferred Stock and the Preferred Stock A shall be preferred as to both earnings, and assets, and in the event of any liquidation, dissolution or winding up of this Corporation, whether voluntary or involuntary, before any assets of the Corporation shall be distributed among or paid over to the holders of the Preference Stock or the Common Stock, the holders of the Preferred Stock of each series shall be entitled to be paid One Hundred Dollars ($100.00) per share, and the holders of the Preferred Stock A of each series shall be entitled to be paid that amount which shall have been fixed and determined for such purpose by the Board of Directors in the resolution or resolutions authorizing the creation and issuance of each such series, in each case together with a sum of money equivalent in the case of each share of stock to all cumulative dividends on the Preferred Stock or the Preferred Stock A, as the case may be, accrued and in arrears thereon, before any distribution of the assets shall be made to the holders of the Preference Stock or the Common Stock, but the holders of the Preferred Stock and the Preferred Stock A shall not be entitled to any further participation in such distribution, and the holders of the Common Stock, subject to the prior rights and preferences of the Preference Stock, shall be entitled, to the exclusion of the holders of the Preferred Stock, the Preferred Stock A and the Preference Stock, to share ratably in all the assets of this Corporation remaining after payment to the holders of the Preferred Stock, and the Preferred Stock A and the Preference Stock of their full preferential amounts. If upon any such liquidation, dissolution or winding up of this Corporation, the assets distributable among the holders of the Preferred Stock and the Preferred Stock A shall be insufficient to permit the payment in full to such holders of the preferential amounts aforesaid, then the entire assets of this Corporation to be distributed shall be distributed among the holders of the Preferred Stock and the Preferred Stock A then outstanding ratably in proportion to the full preferential amounts to which they are respectively entitled.~~

~~11. As hereinbefore set forth, the Preference Stock of all series shall rank junior to all series of the Preferred Stock and the Preferred Stock A with respect to both earnings, and assets, and in the event of any liquidation, dissolution or winding up of this Corporation, whether voluntary or involuntary, after payment to the holders of the Preferred Stock and the Preferred Stock A of all amounts payable to them in such event and before any assets of the Corporation shall be distributed among or paid over to the holders of the Common Stock, the holders of the Preference Stock of each series shall be entitled to be paid that amount which shall have been fixed and determined for such purpose by the Board of Directors in the resolution or resolutions authorizing the creation and issuance of each such series, in each case together with a sum of money equivalent in the case of each share of stock to all cumulative dividends on the Preference Stock~~, ~~accrued and in arrears thereon, before any distribution of the assets shall be made to the holders of the Common Stock, but the holders of the Preference Stock shall not be entitled to any further participation in such distribution, and the holders of the Common Stock shall be entitled, to the exclusion of the holders of the Preferred Stock, the Preferred Stock A and the Preference Stock, to share ratably in all the assets of this Corporation remaining after payment to the holders of the Preferred Stock, the Preferred Stock A and the Preference Stock of their full preferential amounts aforesaid. If upon any such liquidation, dissolution or winding up of this Corporation, the assets distributable among the holders of the Preference Stock shall be insufficient to permit the payment in full to such holders of the preferential amounts aforesaid, then the entire assets of this Corporation to be distributed, after payment to the holders of the Preferred Stock and the Preferred Stock A of all amounts payable to them in such event, shall be distributed among the holders~~

~~of the Preference Stock then outstanding ratably in proportion to the full preferential amounts to which they are entitled.~~

~~Nothing in paragraph 10 or this paragraph 11 shall be deemed to prevent the purchase or redemption of any series of the Preferred Stock, the Preferred Stock A or the Preference Stock, in any manner permitted by paragraph 12. A consolidation or merger of this Corporation with any other corporation or corporations shall not be regarded as a liquidation, dissolution or winding up of this Corporation within the meaning of paragraph 10 or this paragraph 11, but no such consolidation or merger shall in any manner impair the rights or preferences of any of the Preferred Stock, the Preferred Stock A or the Preference Stock~~.

~~12. This Corporation may at the option of the Board of Directors from time to time on any dividend payment date redeem the whole or any part of any series of the Preferred Stock, the Preferred Stock A or the Preference Stock; with respect to the Preferred Stock, by paying One Hundred Dollars ($100.00) per share for each share thereof so redeemed, plus a premium of such additional amount per share as herein fixed and determined for the 4.50% Series Preferred Stock, and in the case of any other series of the Preferred Stock, such premium, if any, as shall have been fixed and determined by the Board of Directors, together in each case with the amount of any dividends accrued and in arrears thereon; with respect to the Preferred Stock A and the Preference Stock, by paying the appropriate amount per share which shall have been fixed and determined by the Board of Directors in the resolution or resolutions authorizing the creation and issuance of each such series of the Preferred Stock A or the Preference Stock, together in each case with the amount of any dividends accrued and in arrears thereon. Notice of such election to redeem shall, not less than thirty days prior to the dividend date upon which the stock is to be redeemed, be mailed to each holder of stock so to be redeemed at his address as it appears on the books of the Corporation. In case less than all of the outstanding Preferred Stock, the Preferred Stock A or the Preference Stock of any series is to be redeemed, the amount to be redeemed may be determined by the Board of Directors; the method of effecting such redemption, whether by lot or pro rata or otherwise, is to be determined by the Board of Directors at the time of issuance. If, on or before the redemption date named in such notice, the funds necessary for such redemption shall have been set aside by the Corporation so as to be available for payment on demand to the holders of the stock so called for redemption, then, notwithstanding that any certificate of stock so called for redemption shall not have been surrendered for cancellation, the dividends thereon shall cease to accrue from and after the date of redemption so designated, and all rights with respect to such stock so called for redemption, including any right to vote or otherwise participate in the determination of any proposed corporate action, shall forthwith after such redemption date cease and determine, except only the right of the holder to receive the redemption price therefor but without interest.~~

~~13. Except as otherwise required by the laws of Delaware and except as may be otherwise provided herein and by the Board of Directors in accordance with paragraphs 2(e) and 4(f), the holders of the Common Stock shall exclusively possess all voting power for the election of directors and for all other purposes, and the holders of the Preferred Stock, the Preferred Stock A and the Preference Stock shall have no voting power, and no owner or holder thereof shall vote thereon or be entitled to receive notice of any meeting of the stockholders; provided that if at any time and whenever cumulative dividends on the Preferred Stock or on the Preferred Stock A shall be in default and unpaid, in whole or in part, for a period of one year, the holders of the Preferred Stock and the Preferred Stock A shall have the same voting powers as the holders of the Common Stock, to-wit: one vote for each share of stock; and further provided that if at any time and whenever cumulative dividends on the Preference Stock shall be in default and unpaid, in whole or in part, for a period of one year, the holders of the Preference Stock shall have the same voting powers as the holders of the Common Stock, to-wit: one vote for each share of stock, and the holders of the Preferred Stock and the Preferred Stock A or the Preference Stock, as the case may be, shall be entitled to~~

~~receive notices of meetings of stockholders, and such voting power shall so continue to vest in the holders of the Preferred Stock and the Preferred Stock A or the Preference Stock, as the case may be, until all arrears in the payment of cumulative dividends on the Preferred Stock and the Preferred Stock A or on the Preference Stock, as the case may be, shall have been paid and the dividends thereon for the current dividend period shall have been declared and the funds for the payment thereof set aside, on the condition, however, that as often as thereafter defaulted dividends shall have been paid in full and provision made for the current dividend as herein provided (and such payment shall be made as promptly as shall be consistent with the best interests of the Corporation), the holders of the Preferred Stock and the Preferred Stock A or of the Preference Stock, as the case may be, shall be divested of such voting power and the voting power shall revest exclusively in the holders of the Common Stock, subject always to the same provisions for the vesting of voting power in the holders of the Preferred Stock and the Preferred Stock A or of the Preference Stock, as the case may be, in case of any similar default or defaults in the payment of cumulative dividends either on the Preferred Stock or the Preferred Stock A or on the Preference Stock, as the case may be, for one year and the revesting of such entire voting power in the holders of the Common Stock, in the event that such default or defaults shall be cured as above provided~~. Dividends and Distributions. Subject to the preferences applicable to any series of Preferred Stock, if any, outstanding at any time, shares of Common Stock shall be entitled to receive dividends, if any, as may be declared from time to time by the Board of Directors out of legally available funds. Subject to the preferences applicable to any series of Preferred Stock, if any, outstanding at any time, the shares of Common Stock are entitled to the net assets of this corporation upon dissolution in accordance with the General Corporation Law of the State of Delaware.

~~14. The vote or consent of the holders of a majority of the Preference Stock at the time outstanding, voting as a class, shall be required for any amendment of the Certificate of Incorporation altering materially any existing provision of the Preference Stock, for the creation, or an increase in the authorized amount, of any class of stock ranking, as to earnings, and assets, prior to, or on a parity with, the Preference Stock, or for an increase in the authorized amount of the Preference Stock; provided, however, that if any amendment of the Certificate of Incorporation shall affect adversely the rights or preferences of one or more, but not all, of the series of the Preference Stock at the time outstanding or shall unequally adversely affect the rights or preferences of different series of the Preference Stock at the time outstanding, the vote or consent of the holders of a majority of such shares of each such series so adversely or unequally adversely affected shall be required in lieu of or (if such vote or consent is required by law) in addition to the vote or consent of the holders of a majority of the outstanding shares of the Preference Stock, voting as a class.~~

~~15.~~ (4) No Pre-emptive Rights. No holder of stock of this Corporation of any class shall have any pre-emptive or preferential rights of subscription to any shares of any class of stock of this Corporation, whether now or hereafter authorized, or to any obligations convertible into stock of the Corporation, issued or sold, nor any right of subscription to any thereof other than such, if any, as the Board of Directors in its discretion may from time to time determine, and at such price as the Board of Directors may from time to time fix and determine pursuant to the authority conferred by this Certificate~~; and any shares of stock or convertible obligations which the Board of Directors may determine to offer for subscription to the holders of stock may, as said Board shall determine, be offered exclusively to holders of the Preferred Stock, to holders of the Preferred Stock A, to holders of the Preference Stock or to holders of the Common Stock, or partly to the holders of the Preferred Stock, partly to the holders of the Preferred Stock A, partly to the holders of the Preference Stock and partly to the holders of the Common Stock, and in such case in such proportions as among said classes of stock as the Board of Directors in its discretion may determine~~ of Incorporation.

~~16. 4.70% Series Preferred Stock~~

~~1. The designation of the Series shall be "4.70% Series Preferred Stock" (Cumulative) (hereinafter called the "4.70% Series") and the number of shares which shall constitute said Series shall be 50,000; and such number shall not be increased.~~

~~2. The annual dividend rate of the 4.70% Series shall be four and seventy hundredths per cent. (4.70%) of the par value of said shares, and no more, and the date from which dividends shall accrue in respect of all shares of the 4.70% Series shall be the date of issue thereof.~~

~~3. The price at which the shares of the 4.70% Series may be redeemed shall be as specified in Paragraph 6 of Article FOURTH of the Certificate of Incorporation, as amended, plus a premium of $2 per share, together with the amount of any dividends accrued and in arrears thereon~~.

~~4. So long as any of the shares of the 4.70% Series are outstanding, in addition to any other vote or consent of stockholders required in the Certificate of Incorporation, as amended, or by law, the vote or consent of the holders of at least sixty-six and two-thirds per cent. (66-2/3%) of the shares of the 4.70% Series at the time outstanding, given in person or by proxy, either in writing without a meeting (if permitted by law) or at any meeting called for the purpose, shall be necessary to effect or validate~~:

~~(a) any amendment, alteration or repeal of any of the provisions of the Certificate of Incorporation, as amended, or By-Laws of the Corporation, which affects adversely the voting powers, rights or preferences of the holders of the 4.70% Series;~~

~~(b) the authorization or creation of, or the increase in the authorized amount of, any stock of any class or any security convertible into stock of any class ranking prior to the Preferred Stock;~~

~~(c) the voluntary dissolution, liquidation or winding up of the affairs of the Corporation, or the sale, lease or conveyance by the Corporation of all or substantially all its property or asset~~s;

~~(d) the merger or consolidation of the Corporation with or into any other corporation, unless the Corporation resulting from such merger or consolidation will have after such merger or consolidation no class of stock and no other securities convertible into stock of any class either authorized or outstanding which stock shall rank prior to the Preferred Stock, except the same number of shares of such stock and the same amount of such other securities with the same rights and preferences as such stock and securities of the Corporation respectively authorized and outstanding immediately preceding such merger or consolidation, and each holder of Preferred Stock immediately preceding such merger or consolidation shall receive the same number of shares, with the same rights and preferences, of the resulting corporation; or~~

~~(e) the purchase or redemption (for sinking fund purposes or otherwise) of less than all of the Preferred Stock at the time outstanding unless the full dividend on all shares of Preferred Stock of all series then outstanding shall have been paid or declared and a sum sufficient for payment thereof set apart; provided, however, that the amendment of the provisions of the Certificate of Incorporation, as amended, so as to authorize or create or to increase the authorized amount (a) of the Common Stock and any other class of stock of the Corporation hereafter authorized over which the Preferred Stock has preference or priority in the payment of dividends or in the distribution of assets on any liquidation, dissolution or winding up of the Corporation or (b) of stock of any class ranking on a parity with the~~

~~Preferred Stock, shall not be deemed to affect adversely the voting powers, rights or preferences of the holders of the 4.70% Series; and provided further, that no such consent of the holders of the 4.70% Series shall be required, if at or prior to the time when such amendment, alteration or repeal is to take effect or when the authorization, creation or increase of any such prior stock or convertible security is to be made, or when such consolidation or merger, voluntary liquidation, dissolution or winding up, sale, lease, conveyance, purchase or redemption is to take effect, as the case may be, either (I) the consent of the holders of at least sixty-six and two-thirds per cent. (66-2/3%) of the shares of the Preferred Stock at the time outstanding shall have been so given to any such action except an amendment, alteration or repeal affecting the shares of the 4.70% Series differently from other series of Preferred Stock, or (II) provision is to be made for the redemption of all shares of the 4.70% Series at the time outstanding.~~

~~5. So long as any shares of the 4.70% Series are outstanding, in addition to any other vote or consent of stockholders required in the Certificate of Incorporation, as amended, or by law, the vote or consent of the holders of a majority of the shares of the 4.70% Series at the time outstanding, given in person or by proxy, either in writing without a meeting (if permitted by law) or at any meeting called for the purpose, shall be necessary to effect or validate any increase in the authorized amount of the Preferred Stock, or the authorization or creation of, or the increase in the authorized amount of, any stock of any class or any security convertible into stock of any class ranking on a parity with the Preferred Stock including any such action taken in connection with the merger or consolidation of the Corporation with or into any other corporation by either party thereto; provided, however, that no such consent of the holders of the 4.70% Series shall be required if, at or prior to the time the authorization or increase of any such parity stock or convertible security or any such additional shares of Preferred Stock is to be made, as the case may be, either (I) the consent of the holders of a majority of the shares of the Preferred Stock at the time outstanding shall have been so given to any such action, or (II) provision is to be made for the redemption of all shares of the 4.70% Series at the time outstanding.~~

~~6. No sinking fund or other retirement obligation shall be provided for the shares of the 4.70% Series.~~

~~17. 5.10% Series Preferred Stock~~

~~1. The designation of the Series shall be “5.10% Series Preferred Stock” (Cumulative) (hereinafter called the “5.10% Series”) and the number of shares which shall constitute said Series shall be 50,000; such number shall not be increased and shall be decreased by the number of shares of said Series at any time retired by the Company.~~

~~2. The annual dividend rate of the 5.10% Series shall be five and ten hundredths per cent (5.10%) of the par value of said shares, and no more, and the date from which dividends shall accrue in respect of all shares of the 5.10% Series shall be the date of issue thereof.~~

~~3. The price at which the shares of the 5.10% Series may be redeemed shall be as specified in paragraph 6 of Article FOURTH of the Certificate of Incorporation, as amended, plus a premium of $2.00 per share, together with the amount of any dividends accrued and in arrears thereon.~~

~~4. So long as any of the shares of the 5.10% Series are outstanding, in addition to any other vote or consent of stockholders required in the Certificate of Incorporation, as amended, or by law, the vote or consent of the holders of at least sixty-six and two-thirds per cent. (66 2/3%) of the shares of the 5.10%~~

~~Series at the time outstanding, given in person or by proxy, either in writing without a meeting (if permitted by law) or at any meeting called for the purpose, shall be necessary to effect or validate~~:

~~(a) any amendment, alteration or repeal of any of the provisions of the Certificate of Incorporation, as amended, or By-Laws of the Corporation, which affects adversely the voting powers, rights or preferences of the holders of the 5.10% Series~~;

~~(b) the authorization or creation of, or the increase in the authorized amount of, any stock of any class or any security convertible into stock of any class ranking prior to the Preferred Stock;~~

~~(c) the voluntary dissolution, liquidation or winding up of the affairs of the Corporation, or the sale, lease or conveyance by the Corporation of all or substantially all its property or assets~~;

~~(d) the merger or consolidation of the Corporation with or into any other corporation, unless the corporation resulting from such merger or consolidation will have after such merger or consolidation no class of stock and no other securities convertible into stock of any class either authorized or outstanding which stock shall rank prior to the Preferred Stock, except the same number of shares of such stock and the same amount of such other securities with the same rights and preferences as such stock and securities of the Corporation respectively authorized and outstanding immediately preceding such merger or consolidation, and each holder of Preferred Stock immediately preceding such merger or consolidation shall receive the same number of shares, with the same rights and preferences, of the resulting corporation; or~~

~~(e) the purchase or redemption (for sinking fund purposes or otherwise) of less than all of the Preferred Stock at the time outstanding unless the full dividend on all shares of Preferred Stock of all series then outstanding shall have been paid or declared and a sum sufficient for payment thereof set apart;~~

~~provided, however, that the amendment of the provisions of the Certificate of Incorporation, as amended, so as to authorize or create or to increase the authorized amount (a) of the Common Stock and any other class of stock of the Corporation hereafter authorized over which the Preferred Stock has preference or priority in the payment of dividends or in the distribution of assets on any liquidation, dissolution or winding up of the Corporation or (b) of any class ranking on a parity with the Preferred Stock, shall not be deemed to affect adversely the voting powers, rights or preferences of the holders of the 5.10% Series; and provided further, that no such consent of the holders of the 5.10% Series shall be required, if at or prior to the time when such amendment, alteration or repeal is to take effect or when the authorization, creation or increase of any such prior stock or convertible security is to be made, or when such consolidation or merger, voluntary liquidation, dissolution or winding up, sale, lease, conveyance, purchase or redemption is to take effect, as the case may be, either (i) the consent of the holders of at least sixty-six and two-thirds per cent. (66 2/3%) of the shares of the Preferred Stock at the time outstanding shall have been so given to any such action except an amendment, alteration or repeal affecting the shares of the 5.10% Series differently from other series of Preferred Stock, or (ii) provision is to be made for the redemption of all shares of the 5.10% Series at the time outstanding.~~

~~5. So long as any shares of the 5.10% Series are outstanding, in addition to any other vote or consent of stockholders required in the Certificate of Incorporation, as amended, or by law, the vote or consent of the holders of a majority of the shares of the 5.10% Series at the time outstanding, given in person or by proxy, either in writing without a meeting (if permitted by law) or at any meeting called for the~~

~~purpose, shall be necessary to effect or validate any increase in the authorized amount of the Preferred Stock, or the authorization or creation of, or the increase in the authorized amount of, any stock of any class or any security convertible into stock of any class ranking on a parity with the preferred Stock including any such action taken in connection with the merger or consolidation of the Corporation with or into any other corporation by either party thereto; provided, however, that no such consent of the holders of the 5.10% Series shall be required if, at or prior to the time the authorization or increase of any such parity stock or convertible security or any such additional shares of Preferred Stock so to be made, as the case may be, either (i) the consent of the holders of a majority of the shares of the Preferred Stock at the time outstanding shall have been so given to any such action, or (ii) provision is to be made for the redemption of all shares of the 5.10% Series at the time outstanding.~~

~~6. As a sinking fund for the retirement of the shares of the 5.10% Series, the Company agrees to purchase (out of any funds of the Company legally available therefor after full dividends on the Preferred Stock of all Series then outstanding for all past dividend periods and for the current period have been paid or declared and a sum sufficient for the payment thereof set apart) 1,000 shares of the 5.10% Series in each year, at the price of $100 per share together with the amount of any dividends accrued and unpaid thereon; provided that no shares of the 5.10% Series shall be purchased pursuant to this paragraph unless tendered by the holders thereof as hereinafter provided; and provided further that the purchase obligation of the Company under this paragraph shall not be cumulative from year to year even though less than 1,000 shares of said Series may be purchased in any year if in such year the Company shall have duly called for tenders and purchased shares duly tendered as hereinafter provided. Shares of the 5.10% Series purchased pursuant to this paragraph shall be cancelled and retired. The Company will, at least 40 and not more than 50 days before each January 1, mail a letter to all holders of record of shares of the 5.10% Series, stating that it is calling for tenders of 1,000 shares of said Series for purchase and retirement under the sinking fund on the following January 1, at $100 per share and accrued and unpaid dividends; the letter shall ask each holder of shares of the 5.10% Series to indicate, by return letter to be received by the Company at a date fixed at least 20 and not more than 25 days before such January 1, the number of shares, if any, which such holder tenders for sale; if more than 1,000 shares are duly tendered by all holders of record, the Company shall first purchase from each holder tendering shares the number of shares tendered up to a number of shares (rounding to the nearest 10 shares) equal as nearly as practicable to 2% of the sum of (i) the number of shares of the 5.10% Series then of record in the name of such holder, and (ii) the number of shares of said Series previously retired that were of record in the name of such holder at the time of their redemption or purchase for retirement, and thereafter purchases shall be made pro rata (as nearly as practicable and rounding to the nearest 10 shares) on the basis of the shares of said Series duly tendered for sale or, in the case of holders duly tendering 1,000 shares, held of record; within three days after the date on which tenders are to be received, the Company shall by letter notify all holders of record of shares of the 5.10% Series of the number of shares tendered and the number of shares held by each holder to be retired; and the Company shall make payment for shares purchased pursuant to this paragraph upon surrender of stock certificates to the Transfer Agent on or after the January 1 retirement date.~~

~~18. Series B Preference Stock~~

~~Section 1. Designation and Amount The shares of such series shall be designated as “Series B Preference Stock” (the “Series B Preference Stock”) and the number of shares constituting the Series B Preference Stock shall be 125,000. Such number of shares may be increased or decreased by resolution of the Board of Directors; provided, that no decrease shall reduce the number of shares of Series B Preference Stock to a number less than the number of shares then outstanding plus the number of shares reserved for issuance upon the exercise of outstanding options, rights or warrants or upon the conversion of any outstanding securities issued by the Corporation convertible into Series B Preference Stock.~~

~~Section 2. Dividends and Distributions.~~

~~(A) Subject to the rights of the holders of any shares of any series of Preferred Stock or Preferred Stock A (or any similar stock) ranking prior and superior to the Series B Preference Stock with respect to dividends, the holders of shares of Series B Preference Stock, equally with holders of all other series of Preference Stock and in preference to the holders of Common Stock, par value $1.00 per share (the "Common Stock"), of the Corporation, and of any other junior stock, shall be entitled to receive, when, as and if declared by the Board of Directors out of funds legally available for the purpose, quarterly dividends payable in cash on the first day of January, April, July, and October in each year (each such date being referred to herein as a "Quarterly Dividend Payment Date"), commencing on the first Quarterly Dividend Payment Date after the first issuance of a share or fraction of a share of Series B Preference Stock, in an amount per share (rounded to the nearest cent) equal to the greater of (a) $1.00 or (b) subject to the provision for adjustment hereinafter set forth, 1,000 times the aggregate per share amount of all cash dividends, and 1,000 times the aggregate per share amount (payable in kind) of all non-cash dividends or other distributions, other than a dividend payable in shares of Common Stock or a subdivision of the outstanding shares of Common Stock (by reclassification or otherwise), declared on the Common Stock since the immediately preceding Quarterly Dividend Payment Date or, with respect to the first Quarterly Dividend Payment Date, since the first issuance of any share or fraction of a share of Series B Preference Stock. In the event the Corporation shall at any time declare or pay any dividend on the Common Stock payable in shares of Common Stock, or effect a subdivision or combination or consolidation of the outstanding shares of Common Stock (by reclassification or otherwise than by payment of a dividend in shares of Common Stock) into a greater or lesser number of shares of Common Stock, then in each such case the amount to which holders of shares of Series B Preference Stock were entitled immediately prior to such event under clause (b) of the preceding sentence shall be adjusted by multiplying such amount by a fraction, the numerator of which is the number of shares of Common Stock outstanding immediately after such event and the denominator of which is the number of shares of Common Stock that were outstanding immediately prior to such event.~~

~~(B) The Corporation shall declare a dividend or distribution on the Series B Preference Stock as provided in paragraph (A) of this Section immediately after it declares a dividend or distribution on the Common Stock (other than a dividend payable in shares of Common Stock); provided that, in the event no dividend or distribution shall have been declared on the Common Stock during the period between any Quarterly Dividend Payment Date and the next subsequent Quarterly Dividend Payment Date, a dividend of $1.00 per share on the Series B Preference Stock shall nevertheless be payable on such subsequent Quarterly Dividend Payment Date.~~

~~(C) Dividends shall begin to accrue and be cumulative on outstanding shares of Series B Preference Stock from the Quarterly Dividend Payment Date next preceding the date of issue of such shares, unless the date of issue of such shares is prior to the record date for the first Quarterly Dividend Payment Date, in which case dividends on such shares shall begin to accrue from the date of issue of such shares, or unless the date of issue is a Quarterly Dividend Payment Date or is a date after the record date for the determination of holders of shares of Series B Preference Stock entitled to receive a quarterly dividend and before such Quarterly Dividend Payment Date, in either of which events such dividends shall begin to accrue and be cumulative from such Quarterly Dividend Payment Date. Accrued but unpaid dividends shall not bear interest. Dividends paid on the shares of Series B Preference Stock in an amount less than the total amount of such dividends at the time accrued and payable on such shares shall be allocated pro rata on a share-by-share basis among all such shares at the time outstanding. The Board of Directors may fix a record date for the determination of holders of shares of Series B Preference Stock entitled to receive payment of a dividend or distribution declared thereon, which record date shall be not more than 60 days prior to the date fixed for the payment thereof.~~

~~Section 3. Voting Rights. The holders of shares of Series B Preference Stock shall have no voting rights except as otherwise provided by law or as set forth in the Corporation's Certificate of Incorporation.~~

~~Section 4. Certain Restrictions.~~

~~(A) Whenever quarterly dividends or other dividends or distributions payable on the Series B Preference Stock as provided in Section 2 are in arrears, thereafter and until all accrued and unpaid dividends and distributions, whether or not declared, on shares of Series B Preference Stock outstanding shall have been paid in full, the Corporation shall not:distributions, whether or not declared, on shares of Series B Preference Stock outstanding shall have been paid in full, the Corporation shall not:~~

~~(i) declare or pay dividends, or make any other distributions, on any shares of stock ranking junior (either as to dividends or upon liquidation, dissolution, or winding up) to the Series B Preference Stock;~~

~~(ii) declare or pay dividends, or make any other distributions, on any shares of stock ranking on a parity (either as to dividends or upon liquidation, dissolution, or winding up) with the Series B Preference Stock, except dividends paid ratably on the Series B Preference Stock and all such parity stock on which dividends are payable or in arrears in proportion to the total amounts to which the holders of all such shares are then entitled;~~

~~(iii) redeem or purchase or otherwise acquire for consideration shares of any stock ranking junior (either as to dividends or upon liquidation, dissolution, or winding up) to the Series B Preference Stock, provided that the Corporation may at any time redeem, purchase or otherwise acquire shares of any such junior stock in exchange for shares of any stock of the Corporation ranking junior (either as to dividends or upon dissolution, liquidation or winding up) to the Series B Preference Stock; or~~

~~(iv) redeem or purchase or otherwise acquire for consideration any shares of Series B Preference Stock, or any shares of stock ranking on a parity with the Series B Preference Stock, except in accordance with a purchase offer made in writing or by publication (as determined by the Board of Directors) to all holders of such shares upon such terms as the Board of Directors, after consideration of the respective annual dividend rates and other relative rights and preferences of the respective series and classes, shall determine in good faith will result in fair and equitable treatment among the respective series or classes.~~

~~(B) The Corporation shall not permit any subsidiary of the Corporation to purchase or otherwise acquire for consideration any shares of stock of the Corporation unless the Corporation could, under paragraph (A) of this Section 4, purchase or otherwise acquire such shares at such time and in such manner.~~

~~Section 5. Reacquired Shares Any shares of Series B Preference Stock purchased or otherwise acquired by the Corporation in any manner whatsoever shall be retired and cancelled promptly after the acquisition thereof. All such shares shall upon their cancellation become authorized but unissued shares of Preference Stock and may be reissued as part of a new series of Preference Stock subject to the conditions and restrictions on issuance set forth herein, in the Certificate of Incorporation, or in any other Certificate of Designations creating a series of Preference Stock or any similar stock or as otherwise required by law.~~

~~Section 6. Liquidation, Dissolution, or Winding Up. Upon any liquidation, dissolution, or winding up of the Corporation, no distribution shall be made (1) to the holders of shares of stock ranking junior (either as to dividends or upon liquidation, dissolution, or winding up) to the Series B Preference Stock unless, prior thereto, the holders of shares of Series B Preference Stock shall have received $1,000 per share, plus an amount equal to accrued and unpaid dividends and distributions thereon, whether or not declared, to the date of such payment,~~

~~provided that the holders of shares of Series B Preference Stock shall be entitled to receive an aggregate amount per share, subject to the provision for adjustment hereinafter set forth, equal to 1,000 times the aggregate amount to be distributed per share to holders of shares of Common Stock, or (2) to the holders of shares of stock ranking on a parity (either as to dividends or upon liquidation, dissolution, or winding up) with the Series B Preference Stock, except distributions made ratably on the Series B Preference Stock and all such parity stock in proportion to the total amounts to which the holders of all such shares are entitled upon such liquidation, dissolution, or winding up. In the event the Corporation shall at any time declare or pay any dividend on the Common Stock payable in shares of Common Stock, or effect a subdivision or combination or consolidation of the outstanding shares of Common Stock (by reclassification or otherwise than by payment of a dividend in shares of Common Stock) into a greater or lesser number of shares of Common Stock, then in each such case the aggregate amount to which holders of shares of Series B Preference Stock were entitled immediately prior to such event under the proviso in clause (1) of the preceding sentence shall be adjusted by multiplying such amount by a fraction the numerator of which is the number of shares of Common Stock outstanding immediately after such event and the denominator of which is the number of shares of Common Stock that were outstanding immediately prior to such event~~.

~~Section 7. Consolidation, Merger, etc. In case the Corporation shall enter into any consolidation, merger, combination, or other transaction in which the shares of Common Stock are exchanged for or changed into other stock or securities, cash and/or any other property, then in any such case each share of Series B Preference Stock shall at the same time be similarly exchanged or changed into an amount per share, subject to the provision for adjustment hereinafter set forth, equal to 1,000 times the aggregate amount of stock, securities, cash and/or any other property (payable in kind), as the case may be, into which or for which each share of Common Stock is changed or exchanged. In the event the Corporation shall at any time declare or pay any dividend on the Common Stock payable in shares of Common Stock, or effect a subdivision or combination or consolidation of the outstanding shares of Common Stock (by reclassification or otherwise than by payment of a dividend in shares of Common Stock) into a greater or lesser number of shares of Common Stock, then in each such case the amount set forth in the preceding sentence with respect to the exchange or change of shares of Series B Preference Stock shall be adjusted by multiplying such amount by a fraction, the numerator of which is the number of shares of Common Stock outstanding immediately after such event and the denominator of which is the number of shares of Common Stock that were outstanding immediately prior to such event.~~

~~Section 8. No Redemption. The shares of Series B Preference Stock shall not be redeemable~~.

~~Section 9. Rank. The Series B Preference Stock shall rank, with respect to the payment of dividends and the distribution of assets, junior to all series of any class of the Corporation's Preferred Stock and Preferred Stock A, shall rank equally with all other series of the Corporation's Preference Stock, and shall rank superior to the Common Stock and any other class or series of junior stock~~.

~~Section 10. Amendment. The Certificate of Incorporation of the Corporation shall not be amended in any manner which would materially alter or change the powers, preferences, or special rights of the Series B Preference Stock so as to affect them adversely without the affirmative vote of the holders of at least a majority of the outstanding shares of Series B Preference Stock, voting together as a single class~~.

~~FIFTH. [RESERVE~~D]

~~SIXTH. [RESERVE~~D]

~~SEVENTH. The Corporation is to have perpetual existence~~.

~~EIGHTH. The private property of the stockholders of the Corporation shall not be subject to the payment of corporate debts to any extent whatever~~.

~~NINTH. In furtherance, and not in limitation of the powers conferred by statute, the Board of Directors is expressly authorized~~:

~~Except as otherwise set forth therein, to make, alter or repeal the By-Laws of the Corporatio~~n.

~~To authorize and cause to be executed mortgages and liens upon the real and personal property~~ of ~~the Corporation~~.

~~To set apart out of any of the funds of the Corporation available for dividends a reserve or reserv~~es ~~for any proper purpose or to abolish any such reserve in the manner in which it was created~~.

~~By resolution or resolutions, passed by a majority of the whole Board to designate one or more committees, each committee to consist of two or more of the directors of the Corporation, which, to the extent provided in said resolution or resolutions or in the By-Laws of the Corporation, shall have and may exercise the powers of the Board of Directors in the management of the business and affairs of the Corporation, and may have power to authorize the seal of the Corporation to be affixed to all papers which may require it. Such committee or committees shall have such name or names as may be stated in the By-Laws of the Corporation or as may be determined from time to time by resolution adopted by the Board of Directors~~.

~~When and as authorized by the affirmative vote of the holders of a majority of the stock issued and outstanding having voting power given at a stockholders' meeting duly called for that purpose, or when authorized by the written consent of the holders of a majority of the voting stock issued and outstanding, to sell, lease or exchange all of the property and assets of the Corporation, including its good will and its corporate franchises, upon such terms and conditions and for such consideration, which may be whole or in part shares of stock in, and/or other securities of, any other corporation or corporations, as its Board of Directors shall deem expedient and for the best interests of the Corporation~~.

~~The Corporation may in its By-Laws confer powers upon its Board of Directors in addition to the foregoing, and in addition to the powers and authorities expressly conferred upon it by statute~~.

~~Both stockholders and directors shall have power, if the By-Laws so provide, to hold their meetings, and to have one or more offices within or without the State of Delaware, and to keep the books of the surviving Corporation (subject to the provisions of the statutes), outside of the State of Delaware at such places as may be from time to time designated by the Board of Directors~~.

~~TENTH. This Corporation reserves the right to amend, alter, change or repeal any provisio~~n ~~contained in this Certificate of Incorporation in the manner now or hereafter prescribed by statute, and all rights conferred upon stockholders herein are granted subject to this reservation~~.

~~ELEVENTH. Whenever a compromise or arrangement is proposed between this Corporation a~~nd ~~its creditors or any class of them and/or between this Corporation and its stockholders or any class of them, any court of equitable jurisdiction within the State of Delaware may, on the application in a summary way of this Corporation or of any creditor or stockholder thereof, or on the application of any receiver or receivers appointed for this Corporation under the provisions of Section 3883 of the Revised Code of 1915 of said State, or on the application of trustees in dissolution or of any receiver or receivers appointed for this Corporation under the~~

~~provisions of Section 43 of the General Corporation Law of the State of Delaware, order a meeting of the creditors or class of creditors, and/or of stockholders or class of stockholders of this Corporation, as the case may be, to be summoned in such manner as the said Court directs. If a majority in number representing three-fourths in value of the creditors or class of creditors, and/or of the stockholders or class of stockholders of this Corporation, as the case may be, agree to any compromise or arrangement and to any reorganization of this Corporation as consequence of such compromise or arrangement, the said compromise or arrangement and the said reorganization shall, if sanctioned by the Court to which the said application has been made, be binding on all the creditors or class of creditors, and/or on all the stockholders or class of stockholders, of this Corporation, as the case may be, and also on this Corporation~~.

~~TWELFTH.~~ [RESERVED]

~~THIRTEENTH~~

ARTICLE V

MATTERS RELATING TO DIRECTORS

(1) Director Powers The business and affairs of the Corporation shall be managed by the Board of Directors. In addition to the powers and authority expressly conferred upon the Board of Directors by statute or by this Certificate of Incorporation or the Corporation's Bylaws, the Board of Directors is hereby empowered to exercise all such powers and do all such things as may be exercised or done by the Corporation unless specifically prohibited by statute or by the Certificate of Incorporation.

(~~a)~~ ~~The business and affairs of the Corporation shall be managed by the Board of Directors consisting of not less than six nor more than fifteen persons. The exact number of directors within the limitations specified in the preceding sentence~~2) Board Size The total number of authorized directors constituting the Board of Directors shall be not less than six nor more than fifteen persons, with the exact number of directors fixed from time to time by the Board of Directors pursuant to a resolution adopted by ~~two-thirds~~a majority of the ~~Continuing~~ Board of Directors.

(3) Vote by Ballot The directors need not be elected by ballot unless required by the ~~By-Laws~~Bylaws of the Corporation.

(4) Term At each annual meeting of stockholders, the directors shall be elected for terms expiring at the next annual meeting of stockholders. Each director shall hold office for the term for which he or she is elected or appointed and until his or her successor shall be elected and qualified or until his or her earlier resignation, removal from office or death. In the event of any increase or decrease in the authorized number of directors, each director then serving as such shall nevertheless continue as director until the expiration of his or her current term, or until his or her earlier resignation, removal from office or death.

(~~b)~~ 5) Vacancies and Newly Created Directorships Newly created directorships resulting from any increase in the authorized number of directors or any vacancies in the Board of Directors resulting from death, resignation, retirement, disqualification, removal from office or other cause shall be filled by a ~~two-thirds~~majority vote of the ~~Continuing Directors~~ directors then in office, or a sole remaining director, although less than a quorum, and directors so chosen shall hold office for a term expiring at the next annual meeting of stockholders. If one or more directors shall resign from the Board of Directors effective as of a future date, such vacancy or vacancies shall be filled pursuant to the provisions hereof, and such new directorship(s) shall become effective when such resignation or resignations shall become effective, and each director so chosen shall hold office for a term expiring at the next annual meeting of stockholders.

~~(c) [RESERVE~~D]

~~(d) Any directors elected pursuant to special voting rights of one or more series of Preferred Stock~~, ~~voting as a class, shall be excluded from, and for no purpose be counted in, the scope and operation of the foregoing provisions, unless expressly stated~~.

~~(e) For purposes of this Article THIRTEENTH, the following terms shall have the meanings hereinafter set forth:~~

~~(i) "Affiliate" or "Associate" shall have the respective meanings ascribed to such terms in the General Rules and Regulations under the Securities Exchange Act of 1934 as in effect on January 1, 1985.~~

~~(ii) A person shall be a "Beneficial Owner" of any Voting Stock~~:

~~(A) which such person or any of its Affiliates or Associates beneficially owns, directly or indirectly; or~~

~~(B) which such person or any of its Affiliates or Associates has (1) the right to acquire (whether such right is exercisable immediately or only after the passage of time), pursuant to any agreement, arrangement or understanding or upon the exercise of conversion rights, exchange rights, warrants or options, or otherwise, or (2) the right to vote pursuant to any agreement, arrangement or understanding; o~~r

~~(C) which are beneficially owned, directly or indirectly, by any other person with which such person or any of its Affiliates or Associates has any agreement, arrangement or understanding for the purpose of acquiring, holding, voting or disposing of any shares of Voting Stock~~.

~~(iii) "Continuing Director" shall mean any member of the Board of Directors of the Corporation who is unaffiliated with, and not a nominee of, any Interested Stockholder and was a member of the Board of Directors prior to the time that any Interested Stockholder became an Interested Stockholder and any successor of a Continuing Director who is unaffiliated with, and not a nominee of, any Interested Stockholder and is designated to succeed a Continuing Director by two-thirds of the Continuing Directors then on the Board of Directors~~.

~~(iv) "Interested Stockholder" shall mean any person (other than the Corporation or any Subsidiary) who or which~~:

~~(A) is the Beneficial Owner, directly or indirectly, of more than 10 percent of the voting power of the then outstanding Voting Stock; or~~

~~(B) is an Affiliate of the Corporation and at any time within the two-year period immediately prior to the date in question, became the Beneficial Owner, directly or indirectly, of more than 10 percent of the voting power of the then outstanding Voting Stock; or~~

~~(C) is an assignee of or has otherwise succeeded to any shares of Voting Stock which were at any time within the two-year period immediately prior to the date in question beneficially owned by any Interested Stockholder, if such assignment or succession shall have occurred in the course of a transaction or series of transactions not involving a public offering within the meaning of the Securities Act of 1933.~~

~~For the purpose of determining whether a person is an Interested Stockholder pursuant to this Article THIRTEENTH, Section (e)(iv), the number of shares of Voting Stock deemed to be outstanding shall include shares deemed owned through application of Section (e)(ii) of this Article THIRTEENTH but shall not include any other shares of Voting Stock which may be issuable pursuant to any agreement, arrangement or understanding, or upon exercise of conversion rights, warrants or options, or otherwise.~~

~~(v) A "person" shall mean any individual, firm, partnership, trust, corporation or other entity.~~

~~(vi) "Subsidiary" means any corporation of which a majority of any class of equity security is owned, directly or indirectly, by the Corporation; provided, however, that for the purposes of the definition of Interested Stockholder set forth in Section (e)(iv) of this Article THIRTEENTH, the term "Subsidiary" shall mean only a corporation of which a majority of each class of equity security is owned, directly or indirectly, by the Corporation.~~

~~(vii) "Voting Stock" shall mean each share of stock of the Corporation generally entitled to vote in elections of directors.~~

~~The Continuing Directors of the Corporation shall have the power and duty to determine, on the basis of information known to them after reasonable inquiry, all facts necessary to determine the applicability of the various provisions of this Article THIRTEENTH, including (A) whether a person is an Interested Stockholder, (B) the number of shares of Voting Stock beneficially owned by any person, and (C) whether a person is an Affiliate or Associate of another. Any such determination made in good faith shall be binding and conclusive on all parties.~~

~~(f) Capitalized terms used and not defined in Article FOURTEENTH or in Article SIXTEENTH of the Certificate of Incorporation which are defined in Section (e) of this Article THIRTEENTH shall have the meanings, for purposes of Article FOURTEENTH and Article SIXTEENTH of the Certificate of Incorporation, ascribed to such terms in Section (e) of this Article THIRTEENTH.~~

<u>FOURTEENTH</u>~~. The Board of Directors, in evaluating any proposal by another party to (a) make~~ a ~~tender or exchange offer for any securities of the Corporation, (b) effect a merger, consolidation or other business combination of the Corporation or (c) effect any other transaction having an effect upon the properties, operations or control of the Corporation similar to a tender or exchange offer for any securities of the Corporation or a merger, consolidation or other business combination of the Corporation, as the case may be~~, ~~whether by an Interested Stockholder or otherwise, may, in connection with the exercise of its judgment as to what is in the best interests of the Corporation and its stockholders, give due consideration to the following~~:

~~(i) the consideration to be received by the Corporation or its stockholders in connection with such transaction in relation not only to the then current market price for the outstanding capital stock of the Corporation, but also to the market price for the capital stock of the Corporation over a period of years, the estimated price that might be achieved in a negotiated sale of the Corporation as a whole or in part~~

~~through orderly liquidation, the premiums over market price for the securities of other corporations in similar transactions, current political, economic and other factors bearing on securities prices and the Corporation's financial condition, future prospects and future value as an independent Corporation~~;

~~(ii) the character, integrity and business philosophy of the other party or parties to the transaction and the management of such party or parties~~;

~~(iii) the business and financial conditions and earnings prospects of the other party or parties to the transaction, including, but not limited to, debt service and other existing or likely financial obligations of such party or parties, the intention of the other party or parties to the transaction regarding the use of the assets of the Corporation to finance the acquisition, and the possible effect of such conditions upon the Corporation and its Subsidiaries and the other elements of the communities in which the Corporation and its Subsidiaries operate or are located~~;

~~(iv) the projected social, legal and economic effects of the proposed action or transaction upon the Corporation or its Subsidiaries, its employees, suppliers, customers and others having similar relationships with the Corporation, and the communities in which the Corporation and its Subsidiaries do business~~;

~~(v) the general desirability of the continuance of the Corporation as an independent entity; and~~

~~(vi) such other factors as the Continuing Directors may deem relevant~~.

~~FIFTEENTH~~ ~~[RESERVE~~D]

ARTICLE VI

STOCKHOLDER ACTIONS

~~SIXTEENTH~~ Any action required or permitted to be taken by the stockholders of the Corporation must be effected at a duly called annual or special meeting of stockholders of the Corporation and may not be effected by any consent in writing by such stockholders. Special meetings of stockholders of the Corporation may be called only by the Chairman or President and shall be called by the Chairman, President or the Secretary upon the written request of ~~two-thirds~~a majority of the ~~Continuing~~ Board of Directors. Stockholders of the Corporation shall not be entitled to request a special meeting of stockholders.

ARTICLE VII

DIRECTOR LIABILITY

~~SEVENTEENTH.~~No director of the Corporation shall be liable to the Corporation or its stockholders for monetary damages for breach of fiduciary duty as a director, except for liability (a) for any breach of the director's duty of loyalty to the Corporation or its stockholders, (b) for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law, (c) under Section 174 of the Delaware General Corporation Law, or (d) for any transaction from which the director derived an improper personal benefit.

ARTICLE VIII

CREDITOR COMPROMISES

Whenever a compromise or arrangement is proposed between this Corporation and its creditors or any class of them and/or between this Corporation and its stockholders or any class of them, any court of equitable jurisdiction within the State of Delaware may, on the application in a summary way of this Corporation or of any creditor or stockholder thereof, or on the application of any receiver or receivers appointed for this Corporation under Section 291 of Title 8 of the Delaware Code, or on the application of trustees in dissolution or of any receiver or receivers appointed for this Corporation under Section 279 of Title 8 of the Delaware Code, order a meeting of the creditors or class of creditors, and/or of stockholders or class of stockholders of this Corporation, as the case may be, to be summoned in such manner as the said Court directs. If a majority in number representing three-fourths in value of the creditors or class of creditors, and/or of the stockholders or class of stockholders of this Corporation, as the case may be, agree to any compromise or arrangement and to any reorganization of this Corporation as consequence of such compromise or arrangement, the said compromise or arrangement and the said reorganization shall, if sanctioned by the Court to which the said application has been made, be binding on all the creditors or class of creditors, and/or on all the stockholders or class of stockholders, of this Corporation, as the case may be, and also on this Corporation.

ARTICLE IX

AMENDMENT OF CERTIFICATE OF INCORPORATION AND BYLAWS

Except as otherwise expressly provided by this Certificate of Incorporation, the Corporation reserves the right to amend, alter, change or repeal any provision of this Certificate of Incorporation in the manner now or hereafter prescribed by law, and all the provisions of this Certificate of Incorporation and all rights conferred on stockholders, directors, officers and other persons in this Certificate of Incorporation are subject to this reserved power. Except as otherwise expressly provided by this Certificate of Incorporation, the Board of Directors shall have the power to adopt, amend or repeal the Corporation’s Bylaws. Any adoption, amendment or repeal of the Corporation’s Bylaws by the Board of Directors shall require the approval of a majority of the Board of Directors. The stockholders of the Corporation shall have the power to adopt, amend or repeal the Corporation’s Bylaws.

[Signature Page Follows]

IN WITNESS WHEREOF, ~~MDUR Newco, Inc.~~ the Corporation has caused ~~its corporate seal to be hereunto affixed, and~~ this Amended and Restated Certificate of Incorporation to be signed by David L. Goodin, its President and Chief Executive Officer, ~~and Daniel S. Kuntz, its Secretary, on December 31, 2018.~~ on [________], 2019.

~~MDUR NEWCO~~ MDU RESOURCES GROUP INC.

~~ATTEST~~:

~~/s/ Daniel S. Kuntz~~
~~Daniel S. Kuntz~~
~~Secretary~~

By: /s/ David L. Goodin
David L. Goodin
President and Chief Executive Officer

[Signature Page to Certificate of Incorporation]

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 2018 was 827,903 shares.

Common Stock Prices

	High	Low	Close
2018			
First Quarter	$28.23	$24.29	$28.16
Second Quarter	29.28	27.05	28.68
Third Quarter	29.62	25.33	25.69
Fourth Quarter	26.96	22.73	23.84
2017			
First Quarter	$29.74	$25.83	$27.37
Second Quarter	27.89	25.58	26.20
Third Quarter	27.73	25.14	25.95
Fourth Quarter	28.22	25.89	26.88

Shareowner Service Plus Plan

The Shareowner Service Plus Plan provides interested investors the opportunity to purchase shares of MDU Resources' common stock and to reinvest all or a percentage of dividends without incurring brokerage commissions or service charges. The plan is sponsored and administered by Equiniti Trust Company, transfer agent and registrar for MDU Resources. For more information, contact Equiniti Trust Company at 877-536-3553 or visit www.shareowneronline.com.

2019 Key Dividend Dates

	Ex-Dividend Date	Record Date	Payment Date
First Quarter	March 13	March 14	April 1
Second Quarter	June 12	June 13	July 1
Third Quarter	September 11	September 12	October 1
Fourth Quarter	December 11	December 12	January 1, 2020

Key dividend dates are subject to the discretion of the Board of Directors.

Annual Meeting

11 a.m. CDT May 7, 2019
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

Jason L. Vollmer
Telephone: 701-530-1755
Email: Jason.Vollmer@MDUResources.com

Transfer Agent and Registrar for All Classes of Stock

Equiniti Trust Company
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

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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www.mdu.com

MDU
LISTED
NYSE

MDU RESOURCES
GROUP, INC.

ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FORM 2
FOR MULTI-STATE GAS COMPANIES
2018

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, 2018

STATE OF OREGON - STATEMENT OF OPERATING INCOME FOR THE YEAR

LINE NO.	ACCOUNT	(REF.) PAGE NO.	GAS UTILITY	
			Current Year	Previous Year
	(a)	(b)	(c)	(d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	62,341,032	64,274,782
3	Operating Expenses			
4	Operation Expenses (401)	4-9	42,747,407	43,880,948
5	Maintenance Expenses (402)	4-9	1,738,467	1,628,355
6	Depreciation Expense (403)	10	6,154,978	5,671,347
7	Amortization & Depletion of Utility Plant (404-405)	10	909,516	766,241
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)		-	-
11	Taxes Other Than Income Taxes (408.1)	11	5,105,787	5,170,826
12	Income Taxes - Federal (409.1)	12	477,754	(726,061)
13	Income Taxes - Other (409.1)	13	(461,582)	(129,101)
14	Provision for Deferred Income Taxes (410.1)	14-21	2,444,547	2,739,613
15	(Less) Provision for Deferred Income Taxes - Cr. (411.1)	14-21	(2,356,657)	-
16	Investment Tax Credit Adjustment - Net (411.4)	22	(9,690)	(8,719)
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)		56,750,527	58,993,449
20	Net Utility Operating Income (Enter Total of line 2 less 19)		5,590,505	5,281,333

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, 2018

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	$ 35,735,955	$ 35,525,211	4,078,092	4,373,150	64,137	61,798
3	481 Commercial and Industrial Sales						
4	Small or Commercial	$ 19,735,290	$ 20,210,186	2,836,254	3,096,877	10,061	9,947
5	Large or Industrial	$ 4,064,217	$ 4,159,797	671,341	713,664	157	152
6	482 Other Sales to Public Authorities						
7	484 Interdepartmental Sales						
8	TOTAL Sales to Ultimate Consumers	$ 59,535,462	$ 59,895,194	7,585,687	8,183,691	74,355	71,897
9	483 Sales for Resale						
10	TOTAL Natural Gas Service Revenues	$ 59,535,462	$ 59,895,194	7,585,687	8,183,691	74,355	71,897
11	Revenues from Manufactured Gas						
12	TOTAL Gas Service Revenues	$ 59,535,462	$ 59,895,194				
13	OTHER OPERATING REVENUES						
14	485 Intracompany Transfers						
15	487 Forfeited Discounts						
16	488 Miscellaneous Service Revenues	$ 146,470	$ 182,797				
17	489 Revenue from Trans. of Gas of Others	$ 4,125,680	$ 4,114,884				
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	$ 12,000				
22	494 Interdepartmental Rents	$ 28,749	$ 25,558				
23	495 Other Gas Revenues	$ 51,692	$ 44,349				
24	TOTAL Other Operating Revenues	$ 4,363,591	$ 4,379,588				
25	TOTAL Gas Operating Revenues	$ 63,899,053	$ 64,274,782				
26	(Less) 496 Provision for Rate Refunds	$ (1,558,020)					
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)	$ 55,471,245		6,914,346			
29	Main Line Industrial Sales (Incl. Main Line Sales to Public Authorities)	$ 4,064,217		671,341			
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))	$ 59,535,462		7,585,687			

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, 2018

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 Account 493 or 494.
4. Provide a subheading and total for each account.

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

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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	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

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

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

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

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	32,942,897	35,281,498
73	804.1 Liquefied Natural Gas Purchases	0	0
74	805 Other Gas Purchases	0	0
75	(Less) 805.1 Purchased Gas Cost Adjustments	(3,808,349)	(4,938,895)
76	805.2 Incremental Gas Cost Adjustments	0	0
77	Total Purchased Gas (Enter Total of lines 67 to 75)	29,134,548	30,342,603
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	506,266	404,388
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	(10,870)	(13,303)
94	Total Gas Used in Utility Operations - Credit (Lines 91 thru 93)	(10,870)	(13,303)
95	813 Other Gas Supply Expenses	88,245	101,025
96	Total Other Gas Supply Exp (Lines 77, 78, 85, 86 thru 89, 94, 95)	29,718,189	30,834,713
97	Total Production Expenses (Total of lines 3, 30, 58, 65 and 96)	29,718,189	30,834,713

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, 2018

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

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 CASCADE NATURAL GAS CORPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2018

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	826,122	735,994
205	871 Distribution Load Dispatching	85,199	112,679
206	872 Compressor Station Labor and Expenses	0	0
207	873 Compressor Station Fuel and Power	0	0
208	874 Mains and Services Expenses	1,282,991	1,223,950
209	875 Measuring and Regulating Station Expenses - General	176,642	186,913
210	876 Measuring and Regulating Station Expenses - Industrial	38,171	19,763
211	877 Measuring & Regulating Station Exp - City Gate Check Station	0	0
212	878 Meter and House Regulator Expenses	231,859	458,032
213	879 Customer Installations Expenses	241,652	448,687
214	880 Other Expenses	1,884,697	1,599,521
215	881 Rents	28,789	33,201
216	Total Operation (Enter Total of lines 204 thru 215)	4,796,122	4,818,740
217	Maintenance		
218	885 Maintenance Supervision and Engineering	221,877	147,320
219	886 Maintenance of Structures and Improvements	441	179
220	887 Maintenance of Mains	415,071	336,082
221	888 Maintenance of Compressor Station Equipment	227	(1,269)
222	889 Maintenance of Meas. and Reg. Sta. Equip. - General	69,974	53,968
223	890 Maintenance of Meas. and Reg. Sta. Equip. - Industrial	5,266	8,477
224	891 Maint. of Meas. & Reg. Sta. Equip. - City Gate Check Station	0	0
225	892 Maintenance of Services	408,632	476,389
226	893 Maintenance of Meters and House Regulators	251,250	417,681
227	894 Maintenance of Other Equipment	357,562	176,967
228	Total Maintenance (Enter Total of lines 218 thru 227)	1,730,300	1,615,794
229	Total Distribution Expenses (Enter Total of lines 216 and 228)	6,526,422	6,434,534
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	35,776	12,405
233	902 Meter Reading Expenses	219,001	192,860
234	903 Customer Records and Collection Expenses	1,404,414	1,461,608
235	904 Uncollectible Accounts	171,038	237,848
236	905 Miscellaneous Customer Accounts Expenses	2	208
237	Total Customer Accounts Expenses (Total of lines 232 thru 236)	1,830,231	1,904,929
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	208,213	98,401
242	909 Informational and Instructional Expenses	2,983	5,684
243	910 Miscellaneous Customer Service and Informational Expenses	86,177	17,119
244	Total Customer Service & Information Expenses (Lines 240 thru 243)	297,373	121,204
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	0	0
249	913 Advertising Expenses	1,293	913
250	916 Miscellaneous Sales Expenses	0	0
251	Total Sales Expenses (Enter Total of lines 247 thru 250)	1,293	913

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, 2018

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	1,882,113	2,264,862
255	921 Office Supplies and Expenses	1,057,859	1,009,853
256	(Less) 922 Administrative Expenses Transferred - Cr.	(101,231)	(96,290)
257	923 Outside Services Employed	577,828	286,641
258	924 Property Insurance	20,620	17,974
259	925 Injuries and Damages	465,943	420,394
260	926 Employee Pensions and Benefits	1,492,230	1,708,831
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	0	0
263	(Less) 929 Duplicate Charges - Cr.	0	0
264	930.1 General Advertising Expenses	8,194	10,711
265	930.2 Miscellaneous General Expenses	297,496	213,092
266	931 Rents	403,147	364,381
267	Total Operation (Enter Total lines 254 thru 266)	6,104,199	6,200,449
268	Maintenance		
269	935 Maintenance of General Plant	8,167	12,561
270	Total Administrative and General Exp (Total of lines 267 and 269)	6,112,366	6,213,010
271	Total Gas O. & M. Exp (Lines 97,177,201,229,237,244,251 and 270)	44,485,874	45,509,303

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:			
275	Production and Gathering	0	0	0
276	Products Extraction	0	0	0
277	Exploration and Development	0	0	0
278	Total Natural Gas	0	0	0
279	Other Gas Supply Expenses	29,718,189	0	29,718,189
280	Total Production	29,718,189	0	29,718,189
281	Underground Storage	0	0	0
282	Other Storage	0	0	0
283	LNG Termininling and Processing	0	0	0
284	Transmission Expenses	0	0	0
285	Distribution Expenses	4,796,122	1,730,300	6,526,422
286	Customer Accounts Expenses	1,830,231	0	1,830,231
287	Customer Service and Informational Expenses	297,373	0	297,373
288	Sales Expenses	1,293	0	1,293
289	Admin and General Expenses	6,104,199	8,167	6,112,366
290	Total Gas O. & M. Expenses	42,747,407	1,738,467	44,485,874

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, 2018

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			909,516			909,516
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	113,173					113,173
9	Distribution Plant	5,697,374					5,697,374
10	General Plant	344,431					344,431
11	Common Plant - Gas						-
12							
13							
14							
15							
16							
17							
18							
19	TOTAL	6,154,978	-	909,516	-	-	7,064,494

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, 2018

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

LINE NO.	KIND OF TAX (a)	AMOUNT (b)
1	Property Taxes	1,685,893
2	Payroll Taxes	579,822
3	Oregon PUC Regulatory Fee	192,824
4	Oregon Department of Energy Fee	85,001
5	City Franchise Taxes	2,535,237
6	Miscellaneous Taxes	27,010
	TOTAL (Must agree with page 1, line 11)	5,105,787

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, 2018

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

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).
2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.
3. Current tax expense on this schedule must match the amount reported on page 1, line 12 of this report. Separately identify adjustments arising from revisions of prior year accruals.
4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	PARTICULARTS (Details) (a)		Amount (b)
1	Gas Operating Revenues		62,341,032
2	Operations and Maintenance Expenses		(44,485,874)
3	Taxes, Other than Income		(5,105,787)
4	State Income (Excise) Tax		(42,647)
5	Interest		(2,960,830)
6	Other Income		(57,029)
7	Federal Income Tax Depreciation		(6,990,994)
8	Other Additions (Subtractions) to Derive Taxable Income		
9	Reserved Revenue		1,558,020
10	Section 174 costs		828,741
11	STIP accrual adjustment		205,009
12	Interest capitalized adj (IRS>books)		131,138
13	50 % of business meals & entertainment		48,579
14	Vacation Accrual adjustment		24,470
15	Payroll taxes - incentive comp		23,004
16	Customer Advances - 2520.000 to 2520.2991		22,400
17	Amort of loss on reacquired debt (4281)		9,411
18	100 % of business entertainment		2,897
19	263A Adjustment - UNICAP		1,064
20	Severance accrual adjustment		-
21	Bad Debt Adjustment		(764)
22	Legal Reserve		(5,151)
23	Prepaid Expenses		(16,180)
24	MGP expense		(39,901)
25	MAOP Deferred Costs		(40,131)
26	Retiree Medical Accrual adjustment		(50,571)
27	SFAS No.87 pension plan accrual		(69,414)
28	FAS158 Adjustment		(250,973)
29	Deferred Gas Costs		(593,187)
30	CIAC		(631,872)
31	Tax Gain (loss) on disposal of assets		(639,909)
32	Repairs Deduction		(794,653)
33	Federal Tax Net Income		2,419,898
34	Show Computation of Tax:		
35	Federal Tax Rate		21%
36	Estimated Federal Tax		508,179
37	Adjustments to Estimated Federal Tax		
38	Difference between 12/31/17 accrual and tax return		54,335
39	Prior year adjustments		-
40	R&D credit		(84,760)
41	Provision for Current Federal Income Tax	409.1	477,754
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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, 2018

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		286,825,673
2	Operations and Maintenance Expenses		(200,944,911)
3	Taxes, Other than Income		(28,430,305)
4	State Income (Excise) Tax		
5	Interest		(12,288,417)
6	Other Income		1,364,668
7	Federal Income Tax Depreciation		(31,497,588)
8	Other Additions (Subtractions) to Derive Taxable Income		
9	Reserved Revenue		4,156,067
10	Section 174 Costs		3,681,658
11	STIP accrual adjustment		815,145
12	MGP expense		700,960
13	Interest capitalized adj (IRS>books)		582,575
14	50 % of business meals & entertainment		164,921
15	Vacation Accrual adjustment		97,296
16	Payroll Taxes - Incentive comp		91,468
17	Amort of loss on reacquired debt (4281)		40,971
18	100 % of business entertainment		11,918
19	263A Adjustment - UNICAP		4,230
20	Severance accrual adjustment		-
21	Bad Debt Adjustment		(10,399)
22	Legal Reserve		(20,482)
23	Prepaid Expenses		(64,335)
24	Customer Advances - 2520.000 to 2520.2991		(81,567)
25	Retiree Medical Accrual adjustment		(201,078)
26	SFAS No.87 pension plan accrual		(275,999)
27	FAS158 Adjustment		(997,905)
28	CIAC		(2,807,073)
29	Tax Gain (loss) on disposal of assets:		(2,845,317)
30	Repairs Deduction		(3,530,221)
31	MAOP Deferred Costs		(4,630,574)
32	Conservation program		(6,309,806)
33	Deferred Gas Costs		(29,884,824)
34	Federal Tax Net Income		(26,283,251)
35	Oregon Apportionment Rate		23.7483%
36	State Tax Net Income		(6,241,825)
37	Show Computation of Tax:		
38	State Tax Rate		7.6%
39			(474,379)
40	Adjustments to Estimated State Tax		
41	Difference between 12/31/17 accrual and tax return		12,797
42	Prior year adjustments		-
43	Tax Retorm		-
44	Provision for Current Federal Income Tax	409.1	(461,582)
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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, 2018

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS COPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

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.

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.

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)	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)	Line No.
1	Electric											1
2												2
3	Other											3
4	TOTAL ELECTRIC											4
5	Gas	16,343,135	(1,215,917)	2009465	(152,659)	114,241	Regulatory accounts related to FAS 158 and OR rate change adjustments	9,677,871	Regulatory accounts related to FAS 158 and OR rate change adjustments	(9,674,133)	17,102,003	5
6												6
7	Other	-									-	7
8	TOTAL GAS	16,343,135	(1,215,917)	2,009,465	(152,659)	114,241		9,677,871		(9,674,133)	17,102,003	8
9	Other (Specify)	-									-	9
10	TOTAL (Account 190)	16,343,135	(1,215,917)	2,009,465	(152,659)	114,241		9,677,871		(9,674,133)	17,102,003	10
11	Classification of Totals											11
12	Federal Income Tax	15,031,334	(1,160,633)	1882988	(143,147)	107,821		9,669,251		(9,662,010)	15,725,604	12
13	State Income Tax	1,311,801	(55,284)	126477	(9,512)	6,420		8,620		(12,123)	1,376,399	13
14	Local Income Tax	-	-	0	-	-		-		-	-	14
15												15
16	Amounts assigned to jurisdictions as follows:											16
17	Federal Income Tax - Washington	See Below	(958,356)	1339724	(107,145)	80,704		9,370,852		(42,047)	12,147,162	17
18	Federal Income Tax - Oregon	See Below	(202,277)	543264	(36,002)	27,117		298,399		(9,619,963)	3,578,442	18
19	State Income Tax - Oregon	1,311,801	(55,284)	126477	(9,512)	6,420		8,620		(12,123)	1,376,399	19
20												20
21												21
22												22

The federal Begining balance in account 190 relating to customer advances 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:

The federal Ending balance in account 190 is allocated by the source of the individual m-items.

	Beginning of Year
Federal Income Tax Acct Balance Relating to Customer Advances	1,055,801
Washington allocation factor	77.16%
Washington Allocated balance relating to Customer Advances	814,656
Oregon allocation factor	22.84%
Oregon Allocated balance relating to Customer Advances	241,145
Remaining balance to be allocated on 3-factor	13,975,533
Oregon allocation factor	24.96%
Oregon allocation	3,488,293
Plus Oregon Allocation of Customer Advances related balance	241,145
Total Oregon Allocated Balance	3,729,438

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, 2018

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:
   - (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.
   - (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.

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)	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)	Line No.
1	Accelerated Amortization (Account 281)											1
2	Electric											2
3	Defense Facilities											3
4	Pollution Control Facilities											4
5	Other											5
6												6
7												7
8	TOTAL Electric (Total of lines 3 thru 7)	-	-	-	-	-	-	-	-	-	-	8
9	Gas											9
10	Defense Facilities											10
11	Pollution Control Facilities											11
12	Other											12
13												13
14												14
15	TOTAL Gas (Total of lines 10 thru 14)	-	-	-	-	-	-	-	-	-	-	15
16	Gas (Specify)										-	16
17	TOTAL (Acct 281) Total of 8, 15 & 16	-	-	-	-	-	-	-	-	-	-	17
18	Classification of TOTAL											18
19	Federal Income Tax	-	-	-	-	-		-		-	-	19
20	State Income Tax	-	-	-	-	-		-		-	-	20
21	Local Income Tax	-	-	-	-	-		-		-	-	21

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, 2018

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.

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.

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)	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)	Line No.
1	Account 282											1
2	Electric	-									-	2
3	Gas	(52,078,937)	(3,070,467)	4,073,006	0	-	182.3 & 254	88,501,500	182.3 & 254	(91,019,441)	(53,594,339)	3
4	Other (Define)	-									-	4
5	Total (Total of Lines 2 thru 4)	(52,078,937)	(3,070,467)	4,073,006	-	-		88,501,500		(91,019,441)	(53,594,339)	5
6	Other (Specify)	-									-	6
7												7
8												8
9	Total (Account 282) Lines 5 thru 8	(52,078,937)	(3,070,467)	4,073,006	-	-		88,501,500		(91,019,441)	(53,594,339)	9
10	Classification of Totals											10
11	Federal Income Tax	(48,413,989)	(2,744,188)	3,862,810	-	-	254	87,877,793	254	(90,345,853)	(49,763,427)	11
12	State Income Tax	(3,664,948)	(326,279)	210,196	-	-	182.3	623,707	182.3	(673,588)	(3,830,912)	12
13	Local Income Tax	-	-	-	-	-		-		-	-	13
	Amounts assigned to jurisdictions as follows:											
	Federal Income Tax - Washington	See Below	(2,179,813)	2,983,822	-	-		3,961,566		(43,242,428)	(38,463,931)	
	Federal Income Tax - Oregon	See Below	(564,375)	878,988	-	-		83,916,227		(47,103,425)	(11,299,496)	
	State Income Tax - Oregon	(3,664,948)	(326,279)	210,196	-	-		623,707		(673,588)	(3,830,912)	

The federal beginning 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:

The federal ending balance in account 282 is allocated based on the source of the individual M-items.

	Beginning of Year
Federal Income Tax Acct Balance Relating to utility plant for ratemaking	(100,214,084)
Washington allocation factor	77.16%
Washington Allocated balance relating to utility plant for ratemaking	(77,325,187)
Oregon allocation factor	22.84%
Oregon Allocated balance relating to utility plant for ratemaking	(22,888,897)
Remaining balance to be allocated on Utility Plant	51,800,095
Oregon allocation factor	22.55%
Oregon allocation	11,680,921
Plus Oregon Allocation of utility plant for ratemaking related balance	(22,888,897)
Total Oregon Allocated Balance	(11,207,976)

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT	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, 2018	CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

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

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited Account 411.1 (d)	CHANGES DURING YEAR Amounts Debited Account 410.2 (e)	CHANGES DURING YEAR Amounts Credited 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)	Line No.
1	Account 283											1
2	Electric	0									-	2
3	Gas	(25,378,377)	(12,845,167)	4,669,970	-	-	Regulatory accounts related to FAS 158 and deferred tax effect of OR State Tax Rate increase	13,691,138	Regulatory accounts related to FAS 158 and deferred tax effect of OR State Tax Rate increase	(15,039,165)	(34,901,601)	3
4	Other (Define)	-									-	4
5	Total (Total of Lines 2 thru 4)	(25,378,377)	(12,845,167)	4,669,970	-	-		13,691,138		(15,039,165)	(34,901,601)	5
6	Other (Specify)	-									-	6
7												7
8												8
9	Total (Account 283) Lines 5 thru 8	(25,378,377)	(12,845,167)	4,669,970	-	-		13,691,138		(15,039,165)	(34,901,601)	9
10	Classification of Totals											10
11	Federal Income Tax	(23,061,620)	(11,812,294)	4,402,947	-	-		13,666,738		(15,035,266)	(31,839,495)	11
12	State Income Tax	(2,316,757)	(1,032,873)	267,023	-	-		24,400		(3,899)	(3,062,106)	12
13	Local Income Tax	-	-	-	-	-		-		-	-	13
	Amounts assigned to jurisdictions as follows:											
	Federal Income Tax - Washington	See below	(11,548,834)	4,072,238	-	-		14,631		(990,013)	(26,957,638)	
	Federal Income Tax - Oregon	See below	(263,460)	330,709	-	-		13,652,107		(14,045,253)	(4,881,857)	
	State Income Tax - Oregon	(2,316,757)	(1,032,873)	267,023	-	-		24,400		(3,899)	(3,062,106)	

The federal beginning 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:

The federal ending balance in account 283 is allocated based on the source of the individual m-items.

	Beginning of Year
Federal Income Tax Acct Balance Relating to Debt Refinancing	(161,931)
Washington allocation factor	77.16%
Washington Allocated balance relating to Debt Refinancing	(124,946)
Oregon allocation factor	22.84%
Oregon Allocated balance relating to Debt Refinancing	(36,985)
Remaining balance to be allocated on 3-factor	(22,899,689)
Oregon allocation factor	24.96%
Oregon allocation	(5,715,762)
Plus Oregon Allocation of Debt refinancing related balance	(36,985)
Total Oregon Allocated Balance	(5,752,747)

OREGON SUPPLEMENT

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, 2018

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

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

Line No.	Account Subdivision	Balance at Beginning of Year	Deferred For Year		Allocations to Current Year's Income		Adjustments	Balance at End of Year	Average period of Allocation to Income
			Account No	Amount	Account No	Amount			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	Gas utility								
2	3%								
3	4%	NOT			411.4	-		NOT	31 Years
4	7%				411.4	-			31 Years
5	10%	ALLOCATED			411.4	(9,690)		ALLOCATED	23 Years
6	Total	0		0		(9,690)			
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, 2018

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)	223,712,403		223,712,403			
4	Property under capital leases	-					
5	Plant purchased or sold	-					
6	Completed construction not classified	3,939,414		3,939,414			
7	Experimental plant unclassified	-					
8	TOTAL (Enter Total of lines 3 thru 7)	227,651,817	-	227,651,817	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	1,794,900		1,794,900			
12	Acquisition Adjustments	-					
13	Total Utility Plant (Enter Total of lines 8 thru 12)	229,446,717	-	229,446,717	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(98,328,316)		(98,328,316)			
15	Net Utility Plant (Line 13 less 14)	131,118,401	-	131,118,401	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(98,236,122)		(98,236,122)			
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	(92,194)		(92,194)			
22	Total In-Service (Total of lines 18 thru 21)	(98,328,316)	-	(98,328,316)	-		-
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)	(98,328,316)	-	(98,328,316)	-		-

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

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	2,947,820			1		2,947,821
5	TOTAL Intangible Plant	3,021,487	-	-	1	-	3,021,488
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, 2018

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, 2018

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	5,818,921			(1)		5,818,920
83	368	Compressor Station Equipment	-					-
84	369	Measuring and Regulating Station Equipment	36,161			1		36,162
85	370	Communications Equipment	-					-
86	371	Other Equipment	-					-
86.a	372	ARO - Transmission	24,974		(81)			24,893
87		TOTAL Transmission Plant	5,900,880	-	(81)	-	-	5,900,799
88		5. Distribution Plant						
89	374	Land and Land Rights	376,880	1,069				377,949
90	375	Structures and Improvements	363,785					363,785
91	376	Mains	92,660,285	9,432,904	(412,977)			101,680,212
92	377	Compressor Station Equipment	-					-
93	378	Measuring and Regulating Equipment - General	10,342,137	284,583	(20,886)			10,605,834
94	379	Measuring and Regulating Equipment - City Gate	-					-
95	380	Services	51,350,519	5,096,499	(162,067)	(1)		56,284,950
96	381	Meters	14,676,177	4,511,458	(2,711,038)	110,128		16,586,725
97	382	Meter Installations	9,108,506	567,179	(6,263)	1	(9,835)	9,659,588
98	383	House Regulators	2,706,169	236,336	(115,785)	20,307		2,847,027
99	384	House Regulator Installations	-					-
100	385	Industrial Measuring and Regulating Station Equipment	1,877,868	318,171	(5,976)		9,835	2,199,898
101	386	Other Property on Customers' Premises	-					-
102	387	Other Equipment	-					-
102.a	388	ARO - Distribution	4,359,610	478,686	(21,472)	10,719		4,827,543
103		TOTAL Distribution Plant	187,821,936	20,926,885	(3,456,464)	141,154	-	205,433,511

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, 2018

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	493,301					493,301
106	390	Structures and Improvements	4,503,032	13,144		(1)		4,516,175
107	391	Office Furniture and Equipment	182,715		(4,239)	1		178,477
108	392	Transportation Equipment	3,790,152	299,131	(337,134)			3,752,149
109	393	Stores Equipment	-					-
110	394	Tools, Shop and Garage Equipment	1,274,627	291,236	(26,312)		(21,109)	1,518,442
111	395	Laboratory Equipment	-					-
112	396	Power Operated Equipment	1,249,120	738,432	(734,509)		(28,518)	1,224,525
113	397	Communication Equipment	1,598,881	6,860				1,605,741
114	398	Miscellaneous Equipment	7,209					7,209
115		SUBTOTAL	13,099,037	1,348,803	(1,102,194)	-	(49,627)	13,296,019
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	13,099,037	1,348,803	(1,102,194)	-	(49,627)	13,296,019
118		TOTAL (Accounts 101 and 106)	209,843,340	22,275,688	(4,558,739)	141,155	(49,627)	227,651,817
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	209,843,340	22,275,688	(4,558,739)	141,155	(49,627)	227,651,817

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, 2018

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

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

Line No.	Description and Location of Property (a)	Date Originally Included in this Acct. (b)	Date Expected to be Used in Utility Service (c)	Balance at End of Year (d)
1	Natural gas lands, leaseholds, and gas rights held for future utility use.			None
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3				
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52	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, 2018

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	Replace 12" HP main in Bend, OR	1,304,280	
2			
3			
4			
5			
6	Minor installation of mains, service lines, measuring and regulating stations,	490,620	
7	meter sets and telemetering, and etc.		
8			
9			
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43	TOTAL -	1,794,900	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, 2018

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	(96,626,376)	(96,626,376)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(5,979,861)	(5,979,861)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(278,751)	(278,751)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	(73,384)	(73,384)		
7.02	Other	-			
8		-			
9	TOTAL Depreciation Provisions for Year (Enter total of lines 3 thru 8)	(6,331,996)	(6,331,996)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	4,558,740	4,558,740		
12	Cost of Removal	1,076,256	1,076,256		
13	Salvage (credits)	(873,770)	(873,770)		
14	TOTAL Net Charges for Plant Retired (enter Total of Lines 11 thru 13)	4,761,226	4,761,226		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	(4,686)	(4,686)		
15.02	Adjustment Due to Transfers/Adjustments & Alloc. Rate Change	(34,290)	(34,290)		
16					
17	Balance End of Year (Enter Total of Lines 1, 9, 14, 15, & 16)	(98,236,122)	(98,236,122)		
	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	(3,628,864)	(3,628,864)		
25	Distribution	(91,161,934)	(91,161,934)		
26	General	(3,837,117)	(3,837,117)		
26.01	Intangible	(73,667)	(73,667)		
26.02	Retirement Work-In-Progress	465,460	465,460		
27	TOTAL (Enter Total of Lines 18 thru 26)	(98,236,122)	(98,236,122)		

NOTE:
Row 15.02 Other Debit or Credit due to transfer of assets, and related depreciation reserve between state jurisdictions

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, 2018

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)	14,274,775		14,274,775			
4	Property Under Capital Leases	-					
5	Plant Purchased or Sold	-					
6	Completed Construction not Classified	363,147		363,147			
7	Experimental Plant Unclassified	-					
8	TOTAL (Enter Total of lines 3 thru 7)	14,637,922	-	14,637,922	-		-
9	Leased to Others	-					
10	Held for Future Use	-					
11	Construction Work In Progress	246,016		246,016			
12	Acquisition Adjustments	-					
13	Total Utility Plant (Lines 8 thru 12)	14,883,938	-	14,883,938	-		-
14	Accumulated Prov For Depr, Amort, & Depl.	(7,453,483)		(7,453,483)			
15	Net Utility Plant (Line 13 less 14)	7,430,455	-	7,430,455	-		-
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service:						
18	Depreciation	(3,158,996)		(3,158,996)			
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	(4,294,487)		(4,294,487)			
22	Total In-Service (Lines 18 thru 21)	(7,453,483)	-	(7,453,483)	-		-
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)	(7,453,483)	-	(7,453,483)	-		-

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, 2018

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	37,957			288		38,245
3	302	Franchises and Consents	-					-
4	303	Miscellaneous Intangible Plant	9,180,318	207,604		69,882		9,457,804
5		TOTAL Intangible Plant	9,218,275	207,604	-	70,170	-	9,496,049
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, 2018

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

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

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

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

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

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT
CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

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	23,687			180		23,867
90	375	Structures and Improvements	99,637			759		100,396
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	123,324	-	-	939	-	124,263

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, 2018

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	238,296			1,814		240,110
106	390	Structures and Improvements	1,472,134	11,777		11,207		1,495,118
107	391	Office Furniture and Equipment	1,768,014	119,569		13,457		1,901,040
108	392	Transportation Equipment	478,242	50,516	(18,499)	3,640	93	513,992
109	393	Stores Equipment	10,755			82		10,837
110	394	Tools, Shop, and Garage Equipment	475,421	135,417	(5,725)	3,619	5,309	614,041
111	395	Laboratory Equipment	24,181		(1,572)	185		22,794
112	396	Power Operated Equipment	(17,572)	3,871	(14,554)	(134)	4,070	(24,319)
113	397	Communication Equipment	224,919	2,406		1,712		229,037
114	398	Miscellaneous Equipment	14,847			113		14,960
115		SUBTOTAL	4,689,237	323,556	(40,350)	35,695	9,472	5,017,610
116	399	Other Tangible Property	-					-
117		TOTAL General Plant	4,689,237	323,556	(40,350)	35,695	9,472	5,017,610
118		TOTAL (Accounts 101 and 106)	14,030,836	531,160	(40,350)	106,804	9,472	14,637,922
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	14,030,836	531,160	(40,350)	106,804	9,472	14,637,922

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, 2018

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
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
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46	T O T A L S -	0	0	0

NAME OF RESPONDENT CASCADE NATURAL GAS CORPORATION	This Report Is: (1) ☑ An Original (2) ☐ A Resubmission	DATE OF REPORT (M,D,Y)	YEAR OF REPORT Dec. 31, 2018

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	No projects equal to or above $500,000		
2			
3	Other general plant work in progress expenditures	246,016	
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48	T O T A L -	246,016	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, 2018

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	(2,879,027)	(2,879,027)		
2	Depreciation Provisions for Year, Charged to:				
3	(403) Depreciation Expense	(175,117)	(175,117)		
4	(413) Exp. of Gas Plant Leased to Others	-			
5	Transportation Expenses - Clearing	(28,560)	(28,560)		
6	Other Clearing Accounts	-			
7	Other Account (specify):				
7.01	ARO Assets	-	-		
7.02	Other	-			
8		-			
9	TOTAL Depreciation Provisions for Year (Enter total of lines 3 thru 8)	(203,677)	(203,677)		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	40,350	40,350		
12	Cost of Removal	-	-		
13	Salvage (credits)	(8,285)	(8,285)		
14	TOTAL Net Charges for Plant Retired (enter Total of Lines 11 thru 13)	32,065	32,065		
15	Other Debit or Credit Items (Describe)				
15.01	Increase/Decrease in Retirement Work in Progress	(86,465)	(86,465)		
15.02	Adjustment Due to Change in Allocation Rate	(21,892)	(21,892)		
16					
17	Balance End of Year (Enter Total of Lines 1, 9, 14, 15, & 16)	(3,158,996)	(3,158,996)		
	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	-	-		
25	Distribution	(105,349)	(105,349)		
26	General	(3,056,164)	(3,056,164)		
26.01	Intangible	-	-		
26.02	Retirement Work-In-Progress	2,517	2,517		
27	TOTAL (Total of Lines 18 thru 26)	(3,158,996)	(3,158,996)		

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

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, 2018

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)					
4	Gas withdrawn from storage					
5	(contra account)			$ 82,746		$ 82,746
6	Other debits or credits					
7	(explain)					
8						
9						
10						
11						
12	Balance, end of year	Not allocated		Not allocated		Not allocated
13	Mcf					
14	Amount per Mcf					

Line No.	Description	Total
15	State basis of segregation of inventory between current and noncurrent portions:	
16		
17	Gas delivered to storage:	
18	Mcf	Not allocated
19	Amount per Mcf	Not allocated
20	Cost basis of gas delivered to storage:	
21	Specify: Own production (give production area, see	
22	uniform system of accounts); average system purchases;	
23	specific purchases (state which purchases).	
24	Does cost of gas delivered to storage include any expenses	
25	for use of respondent's transmission, storage, or other	
26	facilities? If so, give particulars and date of Commission	
27	approval of the accounting.	
28		
29	Gas withdrawn from storage:	
30	Mcf	21,999
31	Amount per Mcf	3.76
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		

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, 2018

STATE OR OREGON - GAS PURCHASES (Accounts 800, 801, 802, 803, 804.1 and 805)

1. Report particulars of gas purchases during the year in the manner prescribed below. (Code numbers to be used in reporting for Columns (d), (e) and (f) will be supplied by the Commission.)

2. Provide subheadings and totals for prescribed accounts as follows:

800 Natural Gas Well Head Purchases
801 Natural Gas Field Line Purchases
802 Natural Gas Gasoline Plant Outlet Purchases
803 Natural Gas Transmission Line Purchases
804 Natural Gas City Gate Purchases
804.1 Liquefied Natural Gas Purchases
805 Other Gas Purchases

Purchases are to be reported in account number sequence; e.g., all purchases charged to Account 800, followed by charges to Account 801, etc. Under each account number, purchases should be reported by states in alphabetical order. Totals are to be shown for each account in Columns (k) and (l) and should agree with the books of account, or any differences reconciled.

3. Purchases may be reported by gas purchase contract totals (at the option of the respondent) where one contract includes two or more FERC producer rate schedules or small producer certificates, provided that the same price is being paid for all gas purchased under the contract. If two or more prices are in effect under the same contract, separate details for each price shall be reported. The name and FERC rate schedule or small producer certificate docket number of each seller included in the contract total shall be listed on separate sheets, clearly cross-referenced. Where two or more prices are in effect, the sellers at each price are to be listed separately.

4. Purchases of less than 100,000 Mcf per year per contract from sellers not affiliated with the reporting company may (at the option of the respondent) be grouped by account number, except when the purchases were permanently discountinued during the reporting year. When grouped purchases are reported, the number of grouped purchases is to be reported in Column (a). Only Columns (a), (k), and (m) are to be completed for grouped purchases; however, the Commission may request additional details when necessary. Grouped non-jurisdictional purchases should be shown on a separate line.

5. Column instructions are as follows:

Columns (a) and (d) - In reporting the names of sellers under FERC rate schedules, use the names as they appear on the filed rate schedules. Abbreviations may be used where necessary. The code number to be used is the Commission-assigned number.

Column (b) - Give the name of the producing field only for purchases at the wellhead or from field lines. The plant name should be given for purchases from gasoline plant outlets. If purchases under a contract are from more than one field or plant, use the name of the one contributing the largest volume. Use a footnote to list the other fields or plants involved.

Column (c) - State the net rate in cents per Mcf as of December 31 for the reported year, applicable to the volume shown in Column (k). The net rate includes all applicable deductions and downward adjustments. The rate is effective and is filed pursuant to applicable statues and regulations and (as to FERC rates schedules) permitted by the Commission to become effective.

Columns (e) and (f) - General Services Administration location code designations are to be used to designate the state and county where the gas is received. Where gas is received in more than one county, use the code designation for the county having the largest volume, and by footnote list the other counties involved.

Column (g) - List the assigned Commission rate schedule number or small producer certificate docket number. Use the designation "NJ" in Column (g) to indicate non-jurisdictional purchases.

Column (h) - In some cases, two or more lines will be required to report a purchase, as when two or more rates are being paid under the same contract, or when purchases under the same rate schedule are charged to more than one account. If for such reasons the producer rate schedule or non-jurisdictional purchase contract appears on more than one line, enter a numerical code (selected by the respondent) in Column (h) to so indicate. Once established, the same numerical suffix is to be used for all subsequent years reporting of the purchase. If the purchase was permanently discontinued during the reporting year, so indicate by an asterisk(*) in column (h). Column (h) is also to be used to enter any Commission assigned letter rate schedule suffix (e.g. R.S. No. 22A).

Column (I) - Show date of the gas purchase contract. If gas is purchased under a renegotiated contract, show the dates of the original and renegotiated contracts on the following line in brackets. If new acreage is dedicated by ratification of an existing contract, show the date of the ratification rather than the date of the original contract. If gas is being sold from a different reservoir than the original dedicated acreage pursuant to Section 2.56 (f) (2) of the Commission's Rules of Practice and Procedure, place the letter "A" after the contract date.

Column (j) - Show, for each purchase, the approximate BTU per cubic foot, determined in accordance with the definition in item No. 7 of the General Instructions for FERC Form 2.

Column (k) - State the volume of purchased gas as finally measured for purposes of determining the amount payable for the gas. Include current year receipts of make-up gas that was paid for in prior years.

Column (l) - State the dollar amount (omit cents) paid and previously paid for the volumes of gas shown in Col. (k).

Column (m) - State the average cost per MCF to the neareast hundredth of a cent. (Column (l) divided by Column (k) multiplied by 100.)

NAME OF RESPONDENT	This Report Is:	DATE OF REPORT	YEAR OF REPORT	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, 2018	CASCADE NATURAL GAS CORPORATION	(1) ☑ An Original (2) ☐ A Resubmission	(M,D,Y)	Dec. 31, 2018

STATE OR OREGON - GAS PURCHASES (Account 800, 801, 802, 803, 804, 804.1 and 805) (Con't)

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)	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	804 Natural Gas City Gate Purchases													1
2	Core firm supply									10.80	7,404,220	$ 20,501,562	277	2
3														3
4	Peaking Services											$ 477,857	n/a	4
5														5
6	Interstate Pipeline Transportation											$ 8,155,129	n/a	6
7														7
8	TOTAL										7,404,220	$ 29,134,548	n/a	8
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53														53

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, 2018

STATE OF OREGON - GAS USED IN UTILITY OPERATIONS - CREDIT (Accounts 810, 811 and 812)

1 Report below particulars of credits during the year to Accounts 810, 811 and 812, which offset charges to operating expenses or other accounts for the cost of gas from the respondent's own supply.
2 Natural gas means either natural gas unmixed, or any mixture of natural and manufactured gas.
3 If the reported MCF for any use is an estimated quantity, state such fact.
4 If any natural gas was used by the respondent for which charge was not made to the appropriate operating expenses or other account, list separately in column (c) the MCF of gas so used, omitting entries in columns (d) and (e).
5 Pressure base of measurement, to be reported in columns (c) and (f) is 14.73 psia at 60 °F.

			Natural Gas			Manufactured Gas	
LINE NO.	PURPOSE FOR WHICH GAS WAS USED (a)	ACCOUNT CHARGED (b)	MCF OF GAS USED (14.73 PSIA AT 60 °F) (c)	AMOUNT OF CREDIT (d)	AMOUNT PER MCF (CENTS) (e)	MCF OF GAS USED (14.73 PSIA AT 60 °F) (f)	AMOUNT OF CREDIT (g)
1	810 Gas used for Compressor Station Fuel - Credit						
2	811 Gas used for Products Extraction - Credit						
3	(a) Gas shrinkage & other usage in respondent's own processing						
4	(b) Gas shrinkage, etc. for respondent's gas processed by others						
5	812 Gas used for Other Utility Operations - Credit	812	4,787	$ 10,870	0	0	0
6	(Report separately for each principal use. Group minor uses).						
7							
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10							
11							
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22	TOTAL		4,787	$ 10,870			

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, 2018

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)	Therms		
1	GAS RECEIVED		Mcf	Therms		Find & Replace WP 2017 with 2018
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					See OR page 2
10	e. City gate under FERC rate schedules		7,399,433	79,920,623	A	EIA - Conversion Factor
11	f. LNG					0.0926
12	g. Other					
13	TOTAL GAS PURCHASED		7,399,433	79,920,623		
14	Gas of others received for transportation		22,534,732	243,395,638	C	
15	Receipts of respondents' gas transported or compressed by others					
16	Exchange gas received					
17	Gas withdrawn from underground storage		168,436	1,819,258	B	
18	Gas received from LNG storage					
19	Gas received from LNG processing					
20	Other receipts: (specify)					
21	TOTAL RECEIPTS		30,102,601	325,135,519		

OREGON SUPPLEMENT 44

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, 2018

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)	Therms
	GAS RECEIVED			Therms
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		671,341	7,251,093	D
39	(ii) Other distribution system sales		6,914,346	74,681,238	E
40	TOTAL DISTRIBUTION SYSTEM SALES		7,585,687	81,932,331	
41	d. Interdepartmental sales				
42	TOTAL SALES		7,585,687	81,932,331	
43					
44	Deliveries of gas transported or compressed for:				
45	a. Other interstate pipeline companies				
46	b. Others		22,534,732	243,395,638	F
47	TOTAL, GAS TRANSPORTED OR COMPRESSED FOR OTHERS		22,534,732	243,395,638	
48	Deliveries of respondent's gas for transportation or compression by others				
49	Exchange gas delivered				
50	Natural gas used by respondent		4,787	51,702	G
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		30,125,206	325,379,671	
57	Production system losses				
58	Storage losses				
59	Transmission system losses				
60	Distribution system losses		(22,605)	(244,152)	H
61	Other losses (specify in so far as possible)				
62	TOTAL UNACCOUNTED FOR		(22,605)	(244,152)	
63	TOTAL SALES, OTHER DELIVERIES & UNACCOUNTED FOR		30,102,601	325,135,519	

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, 2018

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.	205,779	50,004	155,775
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)	324,569	81,629	242,940
6	Director's Fees (paid to MDU for CNGC's share of director's expenses)	363,054	91,308	271,746
7	Miscellaneous under $250,000			
8	2,725 items	278,017	74,555	203,462
9				
10				
	TOTAL	1,171,419	297,496	873,923

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, 2018

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, 2018

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	No on 1631 WA I-1631 was to be a Energy Tax on WA Consumers based upon carbon emissions.	426.4	12,575.00
	TOTAL		12,575.00

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, 2018

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	905,672	227,777
2	MDU/MDUR Allocated - approved in Order 07-418	426.1	6,147	1,546
3	MDU/MDUR Allocated - approved in Order 07-418	426.2	402,569	101,246
4	MDU/MDUR Allocated - approved in Order 07-418	426.4	799	201
5	MDU/MDUR Allocated - approved in Order 07-418	813	140,750	35,399
6	MDU/MDUR Allocated - approved in Order 07-418	875	100,806	25,353
7	MDU/MDUR Allocated - approved in Order 07-418	880	301,853	75,916
8	MDU/MDUR Allocated - approved in Order 07-418	901	42,213	10,617
9	MDU/MDUR Allocated - approved in Order 07-418	902	221,387	55,679
10	MDU/MDUR Allocated - approved in Order 07-418	903	5,258,124	1,322,418
11	MDU/MDUR Allocated - approved in Order 07-418	904	21,961	5,523
12	MDU/MDUR Allocated - approved in Order 07-418	909	11,362	2,857
13	MDU/MDUR Allocated - approved in Order 07-418	910	4,258	1,071
14	MDU/MDUR Allocated - approved in Order 07-418	913	3	1
15	MDU/MDUR Allocated - approved in Order 07-418	920	5,376,819	1,352,270
16	MDU/MDUR Allocated - approved in Order 07-418	921	3,026,367	761,131
17	MDU/MDUR Allocated - approved in Order 07-418	922	(158,954)	(39,977)
18	MDU/MDUR Allocated - approved in Order 07-418	923	252,617	63,533
19	MDU/MDUR Allocated - approved in Order 07-418	925	651	164
20	MDU/MDUR Allocated - approved in Order 07-418	926	19,269	4,846
21	MDU/MDUR Allocated - approved in Order 07-418	930.1	24,240	6,096
22	MDU/MDUR Allocated - approved in Order 07-418	930.2	388,951	97,821
23	MDU/MDUR Allocated - approved in Order 07-418	931	1,490,035	374,744
24	MDU/MDUR Allocated - approved in Order 07-418	932	45	11
25	Other Services	VAR	1,583,934	502,882
	TOTALS		19,421,878	4,989,125

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, 2018

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	CNG Contributions to Winter Help (WA and OR)	426.1	50,000	12,575
3	United Way (WA and OR)	426.1	1,954	866
4	Other Organizations (14 organizations)	426.1	7,423	3,476
5	Total contributions to and memberships in charitable organizations		59,377	16,917
6	(b) Organizations of the Utility Industry:			
7	American Gas Association (Washington D.C.)	426.4/930.2	115,221	28,978
8	Northwest Gas Association (West Linn, OR)	426.4/930.2	70,792	17,804
9	Western Energy Institute (Portland, OR)	921.0/930.2	10,351	2,603
10	North American Energy Standards Board (Houston, TX)	930.2	7,000	1,761
11	Other Organizations (3 organizations)	908.0/930.2/921.0	246	125
12	Total contributions to Organizations of the Utility Industry		203,610	51,271
13	(c) Technical and Professional Organizations			
14	National Association of Corrosion Engineers (Houston, TX)	921.0	2,000	503
15	Other Organizations (20 organizations)	921.0	4,442	1,117
16	Total contributions to Professional Organizations		6,442	1,620
17	(d) Commercial and Trade Organizations			
18	Association of Washington Business (Olympia, WA)	930.2/921.0	33,000	8,300
19	Chamber of Commerce-12 (OR)	426.4/921.0/930.2	12,500	3,892
20	Economic Development Councils-3 (OR)	426.1/930.2	46,977	14,380
21	Other Organizations (3 organizations)	426.1/908.0/930.2	3,086	1,124
22	Total contributions to Commercial and Trade Organizations		95,563	27,696
23	(e) Other Organizations & Donations			
24	MDU Resources expenses (Bismark, ND)	426.1/426.4/921.0	22,061	5,548
25	Grandridge Business Park (Kennewick WA)	930.2	7,837	1,971
26	Other Organizations	426.1921.0/930.2	10,000	2,515
27	Total Other Organizations		39,898	10,034
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
	TOTAL		404,890	107,538

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, 2018

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/	Nicole A. Kivisto	4/	
2	Chairman of the Board 2/	David L. Goodin	4/	
3	Executive VP-Bus Development & Gas Supply 1/	Scott W. Madison	4/	
4	VP Field Operations 1/	Eric P. Martuscelli	4/	
5	VP-Regulatory Affairs & Cust Service 1/	Mark A. Chiles	4/	
6	VP-Human Resources 2/	Anne M. Jones	4/	
7	Assistant Secretary 2/	Julie A. Krenz	4/	
8	General Counsel and Secretary 2/	Daniel S. Kuntz	4/	
9	Assistant Secretary 2/	Karl A. Liepitz	4/	
10	Treasurer 2/	Jason L. Vollmer	4/	
11	Executive VP -Reg Affairs, Cust Service & Administration 1/	Garret Senger	4/	
12	Controller 1/	Tammy J. Nygard	4/	
13	Chief Information Officer 2/	Margaret (Peggy) A. Link	4/	
14	VP-Engineering & Operations Services 1/	Patrick C. Darras	4/	
15	VP-Safety, Process Improvement & Operating Systems 1/	Hart Gilchrist	4/	
16				
17				
18	1/ Salary includes amount allocated to CNGC from MDU			
19	2/ Salary includes amount allocated to CNGC from MDUR			
20	4/ Confidential salary data included on filed reports with OPUC.			
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, 2018

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 RECIPENT (a)	NATURE OF SERVICE (b)	AMOUNT OF PAYMENT (c)
1	Black & Veatch	Consulting	184,299
2	Heath Consultants, Inc	Construction	176,270
3	McDowell Rackner & Gibson, PC	Consulting	129,103
4	ABI Services, LLC	Construction	114,366
5	Deloitte & Touche, LLP	Audit	70,919
6	Parametrix, Inc.	Construction	66,689
7	Anchor QEA	Consulting	63,039
8	Big Schatz Construction	Construction	41,702
9	Veris Law Group, PLLC	Legal	39,049
10	Northwest Metal Fab & Pipe, Inc.	Construction	38,742
11	Garvey Schubert Barer	Legal	38,184
12	Mears Group, Inc.	Construction	37,483
13	Knife River-Western OR Division	Construction	35,427
14	Bend Heating	Construction	34,786
15	One Call Concepts, Inc	Construction	26,714
16	Evergreen Financial Services	Collection	25,506
17	Other		484,868
18			
19			
20			
21			
22			
23			
24			
25			
	TOTAL		1,607,146

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

Oregon Production Statistics (therms)	
Gas Produced	
Gas Purchased	325,135,519
Total Receipts	325,135,519
Gas Sales	325,327,969
Gas used by Company	51,702
Gas Delivered to LNG Storage - Net	
Losses & Billing Delay	(244,152)
Total Disbursements	325,135,519
Oregon Revenue by Service Class	
Residential	$ 35,735,955
Commercial & Industrial	$ 23,799,507
Firm	
Interruptible	
Transportation	$ 4,125,679
Total	$ 63,661,141
Gas Sold in Therms (Oregon)	
Residential	44,047,108
Commercial & Industrial	37,885,223
Firm	
Interruptible	
Transportation	243,395,638
Total	325,327,969
Average Number of Customers	
Residential	64,137
Commercial & Industrial	10,218
Firm	
Interruptible	
Transportation	36
Total	74,391

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Cascade Natural Gas Corporation	(1)An Original (2)A Resubmission	(Mo, Da, Yr)	End of Dec. 31, 2018

Distribution of Salaries and Wages
Oregon Jurisdiction

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	3,287,799			3,287,799
34	Customer Accounts	1,047,262			1,047,262
35	Customer Service and Informational	191,875			191,875
36	Sales	-			-
37	Administrative and General	1,455,735			1,455,735
38	TOTAL Operation (Total of lines 28 thru 37)	5,982,671	-	-	5,982,671
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	1,095,150			1,095,150
46	Administrative and General				
47	TOTAL Maintenance (Total of lines 40 thru 46)	1,095,150	-	-	1,095,150
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)	4,382,949			4,382,949
56	Customer Accounts (Total of line 34)	1,047,262			1,047,262
57	Customer Service and Informational (Total of line 35)	191,875			191,875
58	Sales (Total of line 36)	-			-
59	Administrative and General (Total of lines 37 and 46)	1,455,735			1,455,735
60	Total Operation and Maintenance (Total of lines 50 thru 59)	7,077,821	-	-	7,077,821
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	7,077,821	-	-	7,077,821
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant				
67	Gas Plant	2,045,219			2,045,219
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	2,045,219	-	-	2,045,219
70	Plant Removal (By Utility Departments)				
71	Electric Plant				
72	Gas Plant	54,569			54,569
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	54,569	-	-	54,569
75	PTO/Incentive/Severance Pay Liabilities	247,107			247,107
76	TOTAL Other Accounts	247,107	-	-	247,107
77	TOTAL SALARIES AND WAGES	9,424,716	-	-	9,424,716

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
100-199 Assets and Other Debits.			
1. Utility Plant			
101 Gas plant in service.	1,054,152,346.68	237,821,857.35	22.6%
101.1 Property under capital leases.	-	-	
102 Gas plant purchased or sold.	-	-	
103 Experimental gas plant unclassified.	-	-	
104 Gas plant leased to others.	-	-	
105 Gas plant held for future use.	-	-	
105.1 Production properties held for future use.	-	-	
106 Completed construction not classified - Gas.	23,074,397.22	-	0.0%
107 Construction work in progress - Gas.	12,854,207.49	2,077,811.96	16.2%
108 Accumulated provision for depreciation of gas utility plant.	(473,404,420.84)	(100,466,934.94)	21.2%
109 [Reserved]	-	-	
111 Accumulated provision for amortization and depletion of gas utility plant.	(17,326,335.18)	(4,386,681.03)	25.3%
111.1-111.2 [Reserved]	-	-	
112 [Reserved]	-	-	
113.1-113.2 [Reserved]	-	-	
114 Gas plant acquisition adjustments.	-	-	
115 Accumulated provision for amortization of gas plant acquisition adjustments.	-	-	
116 Other gas plant adjustments.	-	-	
117.1 Gas stored-Base gas.	-	-	
117.2 System balancing gas.	-	-	
117.3 Gas stored in reservoirs and pipelines-noncurrent.	-	-	
117.4 Gas owed to system gas.	-	-	
118 Other utility plant.	-	-	
119 Accumulated provision for depreciation and amortization of other utility plant.	-	-	
2. Other Property and Investments			
121 Nonutility property.	202,030.18	-	0.0%
122 Accumulated provision for depreciation and amortization of nonutility property.	-	-	
123 Investment in associated companies.	-	-	
123.1 Investment in subsidiary companies.	-	-	
124 Other investments.	12,371,315.14	-	0.0%
125 Sinking funds.	-	-	
126 Depreciation fund.	-	-	
128 Other special funds.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
3. Current and Accrued Assets			
131 Cash.	3,203,158.93	-	0.0%
132 Interest special deposits.	-	-	
133 Dividend special deposits.	-	-	
134 Other special deposits.	-	-	
135 Working funds.	1,150.00	-	0.0%
136 Temporary cash investments.	-	-	
141 Notes receivable.	-	-	
142 Customer accounts receivable.	10,776,950.78	-	0.0%
143 Other accounts receivable.	13,165,937.35	-	0.0%
144 Accumulated provision for uncollectible accounts - Cr.	(460,921.84)	-	0.0%
145 Notes receivable from associated companies.	-	-	
146 Accounts receivable from associated companies.	129,531.37	-	0.0%
151 Fuel stock.	-	-	
152 Fuel stock expenses undistributed.	-	-	
153 Residuals and extracted products.	-	-	
154 Plant materials and operating supplies (Major only).	5,694,283.13	2,264,126.71	39.8%
155 Merchandise.	-	-	
156 Other materials and supplies.	-	-	
163 Stores expense undistributed.	-	0.01	
164.1 Gas stored - current.	396,658.82	198,329.42	50.0%
164.2 Liquefied natural gas stored.	1,940,548.63	235,776.66	12.2%
164.3 Liquefied natural gas held for processing.	-	-	
165 Prepayments.	4,497,288.00	411,051.61	9.1%
166 Advances for gas exploration, development, and production.	-	-	
167 Other advances for gas.	-	-	
171 Interest and dividends receivable.	-	-	
172 Rents receivable.	-	-	
173 Accrued utility revenues.	25,164,949.82	-	0.0%
174 Miscellaneous current and accrued assets.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
4. Deferred Debits			
181 Unamortized debt expense.	1,624,524.33	-	0.0%
182.1 Extraordinary property losses.	-	-	
182.2 Unrecovered plant and regulatory study costs.	-	-	
182.3 Other regulatory assets.	56,168,844.81	-	0.0%
183.1 Preliminary natural gas survey and investigation charges.	-	-	
183.2 Other preliminary survey and investigation charges.	-	(0.69)	
184 Clearing accounts.	59,785.30	1,546,515.78	2586.8%
185 Temporary facilities.	-	-	
186 Miscellaneous deferred debits.	79,056,464.36	-	0.0%
187 Deferred losses from disposition of utility plant.	-	-	
188 Research, development, and demonstration expenditures.	-	-	
189 Unamortized loss on reacquired debt.	744,300.47	-	0.0%
190 Accumulated deferred income taxes.	17,102,002.83	192,539.32	1.1%
191 Unrecovered purchased gas costs.	-	-	
200-299 Liabilities and Other Credits.			
5. Proprietary Capital			
201 Common stock issued.	(1,000.00)	-	0.0%
202 Common stock subscribed.	-	-	
203 Common stock liability for conversion.	-	-	
204 Preferred stock issued.	-	-	
205 Preferred stock subscribed.	-	-	
206 Preferred stock liability for conversion.	-	-	
207 Premium on capital stock.	(222,117,553.21)	-	0.0%
208 Donations received from stockholders.	-	-	
209 Reduction in par or stated value of capital stock.	-	-	
210 Gain on resale or cancellation of reacquired capital stock.	-	-	
211 Miscellaneous paid-in capital.	-	-	
212 Installments received on capital stock.	-	-	
213 Discount on capital stock.	-	-	
214 Capital stock expense.	-	-	
215 Appropriated retained earnings.	-	-	
216 Unappropriated retained earnings.	(30,645,897.45)	-	0.0%
216.1 Unappropriated undistributed subsidiary earnings.	-	-	
217 Reacquired capital stock.	-	-	
219 Other Comprehensive Income	(2,318,457.36)	-	0.0%

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
6. Long-Term Debt			
221 Bonds.	-	-	
222 Reacquired bonds.	-	-	
223 Advances from associated companies.	-	-	
224 Other long-term debt.	(268,211,000.00)	-	0.0%
225 Unamortized premium on long-term debt.	-	-	
226 Unamortized discount on long-term debt - Debit.	-	-	
7. Other Noncurrent Liabilities.			
227 Obligations under capital leases - noncurrent.	-	-	
228.1 Accumulated provision for property insurance.	-	-	
228.2 Accumulated provision for injuries and damages.	(13,232,380.74)	-	0.0%
228.3 Accumulated provision for pensions and benefits.	(5,811,780.27)	-	0.0%
228.4 Accumulated miscellaneous operating provisions.	(24,135.00)	-	0.0%
229 Accumulated provision for rate refunds.	(1,558,019.97)	-	0.0%
8. Current and Accrued Liabilities			
230 Asset Retirement Obligations.	(66,788,045.99)	-	0.0%
231 Notes payable.	-	-	
232 Accounts payable.	(66,439,118.25)	-	0.0%
233 Notes payable to associated companies.	-	-	
234 Accounts payable to associated companies.	(2,007,577.17)	-	0.0%
235 Customer deposits.	(893,105.13)	-	0.0%
236 Taxes accrued.	(7,285,166.28)	-	0.0%
237 Interest accrued.	(3,155,341.44)	-	0.0%
238 Dividends declared.	(2,960,000.00)	-	0.0%
239 Matured long-term debt.	-	-	
240 Matured interest.	-	-	
241 Tax collections payable.	(1,309.05)	-	0.0%
242 Miscellaneous current and accrued liabilities.	(8,958,796.97)	-	0.0%
243 Obligations under capital leases - current.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
9. Deferred Credits			
252 Customer advances for construction.	(4,315,900.87)	(410,517.98)	9.5%
253 Other deferred credits.	31,014,245.67	-	0.0%
254 Other regulatory liabilities.	(62,967,793.41)	-	0.0%
255 Accumulated deferred investment tax credits.	(243,929.00)	-	0.0%
256 Deferred gains from disposition of utility plant.	-	-	
257 Unamortized gain on reacquired debt.	-	-	
281 Accumulated deferred income taxes - Accelerated amortization property.	-	-	
282 Accumulated deferred income taxes - Other property.	(53,594,338.57)	(26,936,295.17)	50.3%
283 Accumulated deferred income taxes - Other.	(34,901,600.99)	(48,688.49)	0.1%
300-399 Plant Accounts.			
1. Intangible Plant			
301 Organization.	-	-	
302 Franchises and consents.	-	-	
303 Miscellaneous intangible plant.	-	-	
2. Production Plant			
a. manufactured gas production plant			
304 Land and land rights.	-	-	
305 Structures and improvements.	-	-	
306 Boiler plant equipment.	-	-	
307 Other power equipment.	-	-	
308 Coke ovens.	-	-	
309 Producer gas equipment.	-	-	
310 Water gas generating equipment.	-	-	
311 Liquefied petroleum gas equipment.	-	-	
312 Oil gas generating equipment.	-	-	
313 Generating equipment - Other processes.	-	-	
314 Coal, coke, and ash handling equipment.	-	-	
315 Catalytic cracking equipment.	-	-	
316 Other reforming equipment.	-	-	
317 Purification equipment.	-	-	
318 Residual refining equipment.	-	-	
319 Gas mixing equipment.	-	-	
320 Other equipment.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
b. natural gas production plant			
B.1. Natural Gas Production and Gathering Plant			
325.1 Producing lands.	-	-	
325.2 Producing leaseholds.	-	-	
325.3 Gas rights.	-	-	
325.4 Rights-of-way.	-	-	
325.5 Other land and land rights.	-	-	
326 Gas well structures.	-	-	
327 Field compressor station structures.	-	-	
328 Field measuring and regulating station structures.	-	-	
329 Other structures.	-	-	
330 Producing gas wells - Well construction.	-	-	
331 Producing gas wells - Well equipment.	-	-	
332 Field lines.	-	-	
333 Field compressor station equipment.	-	-	
334 Field measuring and regulating station equipment.	-	-	
335 Drilling and cleaning equipment.	-	-	
336 Purification equipment.	-	-	
337 Other equipment.	-	-	
338 Unsuccessful exploration and development costs.	-	-	
B.2. Products Extraction Plant			
340 Land and land rights.	-	-	
341 Structures and improvements.	-	-	
342 Extraction and refining equipment.	-	-	
343 Pipe lines.	-	-	
344 Extracted product storage equipment.	-	-	
345 Compressor equipment.	-	-	
346 Gas measuring and regulating equipment.	-	-	
347 Other equipment.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
3. Natural Gas Storage and Processing Plant			
a. underground storage plant			
350.1 Land.	-	-	
350.2 Rights-of-way.	-	-	
351 Structures and improvements.	-	-	
352 Wells.	-	-	
352.1 Storage leaseholds and rights.	-	-	
352.2 Reservoirs.	-	-	
352.3 Nonrecoverable natural gas.	-	-	
353 Lines.	-	-	
354 Compressor station equipment.	-	-	
355 Measuring and regulating equipment.	-	-	
356 Purification equipment.	-	-	
357 Other equipment.	-	-	
b. other storage plant			
360 Land and land rights.	-	-	
361 Structures and improvements.	-	-	
362 Gas holders.	-	-	
363 Purification equipment.	-	-	
363.1 Liquefaction equipment.	-	-	
363.2 Vaporizing equipment.	-	-	
363.3 Compressor equipment.	-	-	
363.4 Measuring and regulating equipment.	-	-	
363.5 Other equipment.	-	-	
c. base load liquefied natural gas terminaling and processing plant			
364.1 Land and land rights .	-	-	
364.2 Structures and improvements.	-	-	
364.3 LNG processing terminal equipment.	-	-	
364.4 LNG transportation equipment.	-	-	
364.5 Measuring and regulating equipment.	-	-	
364.6 Compressor station equipment.	-	-	
364.7 Communication equipment.	-	-	
364.8 Other equipment.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
4. Transmission Plant			
365.1 Land and land rights.	-	-	
365.2 Rights-of-way.	-	-	
366 Structures and improvements.	-	-	
367 Mains.	-	-	
368 Compressor station equipment.	-	-	
369 Measuring and regulating station equipment.	-	-	
370 Communication equipment.	-	-	
371 Other equipment.	-	-	
5. Distribution Plant			
374 Land and land rights.	-	-	
375 Structures and improvements.	-	-	
376 Mains.	-	-	
377 Compressor station equipment.	-	-	
378 Measuring and regulating station equipment - General.	-	-	
379 Measuring and regulating station equipment - City gate check stations.	-	-	
380 Services.	-	-	
381 Meters.	-	-	
382 Meter installations.	-	-	
383 House regulators.	-	-	
384 House regulatory installations.	-	-	
385 Industrial measuring and regulating station equipment.	-	-	
386 Other property on customers' premises.	-	-	
387 Other equipment.	-	-	
6. General Plant			
389 Land and land rights.	-	-	
390 Structures and improvements.	-	-	
391 Office furniture and equipment.	-	-	
392 Transportation equipment.	-	-	
393 Stores equipment.	-	-	
394 Tools, shop and garage equipment.	-	-	
395 Laboratory equipment.	-	-	
396 Power operated equipment.	-	-	
397 Communication equipment.	-	-	
398 Miscellaneous equipment.	-	-	
399 Other tangible property.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
400-432, 434-435 Income Accounts.			
1. Utility Operating Income			
operating expenses			
400 Operating revenues.	(262,501,258.07)	(59,535,461.76)	22.7%
401 Operation expense.	-	-	
402 Maintenance expense.	-	-	
403 Depreciation expense.	26,303,412.61	6,154,977.53	23.4%
404.1 Amortization and depletion of producing natural gas land and land rights.	-	-	
404.2 Amortization of underground storage land and land rights.	3,486,360.40	909,516.17	26.1%
404.3 Amortization of other limited-term gas plant.	-	-	
405 Amortization of other gas plant.	-	-	
406 Amortization of gas plant acquisition adjustments.	-	-	
407.1 Amortization of property losses, unrecovered plant and regulatory study costs.	-	-	
407.2 Amortization of conversion expense.	-	-	
407.3 Regulatory debits.	-	-	
407.4 Regulatory credits.	-	-	
408 [Reserved]	-	-	
408.1 Taxes other than income taxes, utility operating income.	28,430,305.46	5,105,787.71	18.0%
409 [Reserved]	-	-	
409.1 Income taxes, utility operating income.	(5,881,800.20)	16,172.38	-0.3%
410 [Reserved]	-	-	
410.1 Provision for deferred income taxes, utility operating income.	17,131,551.19	2,444,547.51	14.3%
411 [Reserved]	-	-	
411.1 Provision for deferred income taxes - Credit, utility operating income.	(10,752,440.66)	(2,356,656.79)	21.9%
411.3 [Reserved]	-	-	
411.4 Investment tax credit adjustments, utility operations.	(42,184.00)	(9,689.65)	23.0%
411.6 Gains from disposition of utility plant.	-	-	
411.7 Losses from disposition of utility plant. Total utility operating expenses.	-	-	
other operating income			
412 Revenues from gas plant leased to others.	-	-	
413 Expenses of gas plant leased to others.	-	-	
414 Other utility operating income. Net utility operating income.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
2. Other Income and Deductions			
a. other income			
415 Revenues from merchandising, jobbing and contract work.	-	-	
416 Costs and expenses of merchandising, jobbing and contract work.	-	-	
417 Revenues from nonutility operations.	(8,686.95)	(2,184.77)	25.2%
417.1 Expenses of nonutility operations.	-	-	
418 Nonoperating rental income.	-	-	
418.1 Equity in earnings of subsidiary companies.	-	-	
419 Interest and dividend income.	-	-	
419.0 Interest and dividend income.	(513,667.75)	(86,279.48)	16.8%
419.1 Allowance for other funds used during construction.	(47,519.35)	(9,188.42)	19.3%
421 Miscellaneous nonoperating income.	(25,876.43)	(6,507.91)	25.1%
421.1 Gain on disposition of property. Total other income.	-	-	
b. other income deductions			
421.2 Loss on disposition of property.	-	-	
425 Miscellaneous amortization.	-	-	
426 [Reserved]	-	-	
426.1 Donations.	147,336.40	42,474.17	28.8%
426.2 Life insurance.	452,956.61	113,918.59	25.2%
426.3 Penalties.	50.76	12.77	25.2%
426.4 Expenditures for certain civic, political and related activities.	165,577.54	41,525.80	25.1%
426.5 Other deductions. Total other income deductions. Total other income and deductions.	615,677.14	-	0.0%
c. taxes applicable to other income and deductions			
408.2 Taxes other than income taxes, other income and deductions.	1,144.68	-	0.0%
409.2 Income taxes, other income and deductions.	(271,794.13)	(68,997.75)	25.4%
410.2 Provision for deferred income taxes, other income and deductions.	152,658.83	45,513.56	29.8%
411.2 Provision for deferred income taxes - Credit, other income and deductions.	(114,240.93)	(33,537.14)	29.4%
411.5 Investment tax credit adjustments, nonutility operations.	-	-	
420 Investment tax credits. Total taxes on other income and deductions. Net other income and dedu	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
3. Interest Charges			
427 Interest on long-term debt.	11,687,433.17	2,684,603.39	23.0%
428 Amortization of debt discount and expense.	200,172.75	45,979.67	23.0%
428.1 Amortization of loss on reacquired debt.	40,970.64	9,411.00	23.0%
429 Amortization of premium on debt - Credit.	-	-	
429.1 Amortization of gain on reacquired debt - Credit.	-	-	
430 Interest on debt to associated companies.	-	-	
431 Other interest expense.	359,840.29	220,835.73	61.4%
432 Allowance for borrowed funds used during construction - Credit. Net interest charges.	(291,152.66)	(46,832.34)	16.1%
4. Extraordinary Items			
434 Extraordinary income.	-	-	
435 Extraordinary deductions.	-	-	
409.3 Income taxes, extraordinary items. Net income	-	-	
433, 436-439 Retained Earnings Accounts.			
Retained Earnings Chart of Accounts			
433 Balance transferred from income.	-	-	
436 Appropriations of retained earnings.	-	-	
437 Dividends declared - preferred stock.	-	-	
438 Dividends declared - common stock.	10,610,000.00	-	0.0%
439 Adjustments to retained earnings.	273,680.51	68,830.65	25.2%
480-499 Revenue Accounts.			
1. Sales of Gas			
480 Residential sales.	-	-	
481 Commercial and industrial sales.	-	-	
482 Other sales to public authorities.	-	-	
483 Sales for resale.	-	-	
484 Interdepartmental sales.	-	-	
485 Intracompany transfers.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
2. Other Operating Revenues			
487 Forfeited discounts.	-	-	
488 Miscellaneous service revenues.	(925,186.56)	(146,469.86)	15.8%
489.0 Revenues from transportation of gas of others through gathering facilities.	(27,295,346.95)	(4,134,904.65)	15.1%
489.1 Revenues from transportation of gas of others through gathering facilities.	163,338.82	9,225.66	5.6%
489.2 Revenues from transportation of gas of others through transmission facilities.	-	-	
489.3 Revenues from transportation of gas of others through distribution facilities.	-	-	
489.4 Revenues from storing gas of others.	-	-	
490 Sales of products extracted from natural gas.	-	-	
491 Revenues from natural gas processed by others.	-	-	
492 Incidental gasoline and oil sales.	-	-	
493 Rent from gas property.	(11,100.00)	(11,000.00)	99.1%
494 Interdepartmental rents.	(114,312.00)	(28,749.48)	25.2%
495 Other gas revenues.	(124,553.16)	(51,691.85)	41.5%
496 Provision for rate refunds	3,982,745.05	1,558,019.97	39.1%
700-899 Production, Transmission and Distribution Expenses.			
1. Production Expenses			
a. manufactured gas production			
A.1. Steam Production			
Operation			
700 Operation supervision and engineering.	-	-	
701 Operation labor.	-	-	
702 Boiler fuel.	-	-	
703 Miscellaneous steam expenses.	-	-	
704 Steam transferred - Credit.	-	-	
Maintenance			
705 Maintenance supervision and engineering.	-	-	
706 Maintenance of structures and improvements.	-	-	
707 Maintenance of boiler plant equipment.	-	-	
708 Maintenance of other steam production plant	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
A.2. Manufactured Gas Production			
Operation			
710 Operation supervision and engineering	-	-	
Production Labor and Expenses			
711 Steam expenses.	-	-	
712 Other power expenses.	-	-	
713 Coke oven expenses.	-	-	
714 Producer gas expenses.	-	-	
715 Water gas generating expenses.	-	-	
716 Oil gas generating expenses.	-	-	
717 Liquefied petroleum gas expenses.	-	-	
718 Other process production expenses.	-	-	
gas fuels			
719 Fuel under coke ovens.	-	-	
720 Producer gas fuel.	-	-	
721 Water gas generator fuel.	-	-	
722 Fuel for oil gas.	-	-	
723 Fuel for liquefied petroleum gas process.	-	-	
724 Other gas fuels.	-	-	
gas raw materials			
725 Coal carbonized in coke ovens.	-	-	
726 Oil for water gas.	-	-	
727 Oil for oil gas.	-	-	
728 Liquefied petroleum gas.	-	-	
729 Raw materials for other gas processes.	-	-	
730 Residuals expenses.	-	-	
731 Residuals produced - Credit.	-	-	
732 Purification expenses.	-	-	
733 Gas mixing expenses.	-	-	
734 Duplicate charges - Credit.	-	-	
735 Miscellaneous production expenses.	-	-	
736 Rents.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
Maintenance			
740 Maintenance supervision and engineering.	-	-	
741 Maintenance of structures and improvements.	-	-	
742 Maintenance of production equipment.	-	-	
b. natural gas production expenses			
B.1. Natural Gas Production and Gathering			
Operation			
750 Operation supervision and engineering.	-	-	
751 Production maps and records.	-	-	
752 Gas wells expenses.	-	-	
753 Field lines expenses.	-	-	
754 Field compressor station expenses.	-	-	
755 Field compressor station fuel and power.	-	-	
756 Field measuring and regulating station expenses.	-	-	
757 Purification expenses.	-	-	
758 Gas well royalties.	-	-	
759 Other expenses.	-	-	
760 Rents.	-	-	
Maintenance			
761 Maintenance supervision and engineering.	-	-	
762 Maintenance of structures and improvements.	-	-	
763 Maintenance of producing gas wells.	-	-	
764 Maintenance of field lines.	-	-	
765 Maintenance of field compressor station equipment.	-	-	
766 Maintenance of field measuring and regulating station equipment.	-	-	
767 Maintenance of purification equipment.	-	-	
768 Maintenance of drilling and cleaning equipment.	-	-	
769 Maintenance of other equipment	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
B.2. Products Extraction			
Operation			
770 Operation supervision and engineering.	-	-	
771 Operation labor.	-	-	
772 Gas shrinkage.	-	-	
773 Fuel.	-	-	
774 Power.	-	-	
775 Materials.	-	-	
776 Operation supplies and expenses.	-	-	
777 Gas processed by others.	-	-	
778 Royalties on products extracted.	-	-	
779 Marketing expenses.	-	-	
780 Products purchased for resale.	-	-	
781 Variation in products inventory.	-	-	
782 Extracted products used by the utility - Credit.	-	-	
783 Rents.	-	-	
Maintenance			
784 Maintenance supervision and engineering.	-	-	
785 Maintenance of structures and improvements.	-	-	
786 Maintenance of extraction and refining equipment.	-	-	
787 Maintenance of pipe lines.	-	-	
788 Maintenance of extracted products storage equipment.	-	-	
789 Maintenance of compressor equipment.	-	-	
790 Maintenance of gas measuring and regulating equipment.	-	-	
791 Maintenance of other equipment.	-	-	
c. exploration and development expenses			
Operation			
795 Delay rentals.	-	-	
796 Nonproductive well drilling.	-	-	
797 Abandoned leases.	-	-	
798 Other exploration.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
d. other gas supply expenses			
Operation			
800 Natural gas well head purchases.	-	-	
800.1 Natural gas well head purchases, intracompany transfers.	-	-	
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.	177,359,949.08	32,942,897.07	18.6%
804.1 Liquefied natural gas purchases.	-	-	
805 Other gas purchases.	-	-	
805.1 Purchased gas cost adjustments.	(37,057,421.47)	(3,808,349.05)	10.3%
806 Exchange gas.	-	-	
807 Purchased gas expenses.	-	-	
808.1 Gas withdrawn from storage - Debt.	4,132,770.93	506,265.92	12.3%
808.2 Gas delivered to storage - Credit.	(4,963,076.44)	-	0.0%
809.1 Withdrawals of liquefied natural gas held for processing - Debt.	-	-	
809.2 Deliveries of natural gas for processing - Credit.	-	-	
810 Gas used for compressor station fuel - Credit.	-	-	
811 Gas used for products extraction - Credit.	-	-	
812 Gas used for other utility operations - Credit.	(59,073.97)	(10,869.99)	18.4%
813 Other gas supply expenses.	371,671.96	98,756.65	26.6%
2. Natural Gas Storage, Terminaling and Processing Expenses			
a. underground storage expenses			
814 Operation supervision and engineering.	-	-	
815 Maps and records.	-	-	
816 Wells expenses.	-	-	
817 Lines expenses.	-	-	
818 Compressor station expenses.	-	-	
819 Compressor station fuel and power.	-	-	
820 Measuring and regulating station expenses.	-	-	
821 Purification expenses.	-	-	
822 Exploration and development.	-	-	
823 Gas losses.	-	-	
824 Other expenses.	-	-	
825 Storage well royalties.	-	-	
826 Rents.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
Maintenance			
830 Maintenance supervision and engineering.	-	-	
831 Maintenance of structures and improvements.	-	-	
832 Maintenance of reservoirs and wells.	-	-	
833 Maintenance of lines.	-	-	
834 Maintenance of compressor station equipment.	-	-	
835 Maintenance of measuring and regulating station equipment.	-	-	
836 Maintenance of purification equipment.	-	-	
837 Maintenance of other equipment.	-	-	
b. other storage expenses			
Operation			
840 Operation supervision and engineering.	-	-	
841 Operation labor and expenses.	-	-	
842 Rents.	-	-	
842.1 Fuel.	-	-	
842.2 Power.	-	-	
842.3 Gas losses.	-	-	
Maintenance			
843.1 Maintenance supervision and engineering.	-	-	
843.2 Maintenance of structures and improvements.	-	-	
843.3 Maintenance of gas holders.	-	-	
843.4 Maintenance of purification equipment.	-	-	
843.5 Maintenance of liquefaction equipment.	-	-	
843.6 Maintenance of vaporizing equipment.	-	-	
843.7 Maintenance of compressor equipment.	-	-	
843.8 Maintenance of measuring and regulating equipment.	-	-	
843.9 Maintenance of other equipment.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
c. liquefied natural gas terminaling and processing expenses			
Operation			
844.1 Operation supervision and engineering.	-	-	
844.2 LNG processing terminal labor and expenses.	-	-	
844.3 Liquefaction processing labor and expenses.	-	-	
844.4 LNG transportation labor and expenses.	-	-	
844.5 Measuring and regulating labor and expenses.	-	-	
844.6 Compressor station labor and expenses.	-	-	
844.7 Communication system expenses.	-	-	
844.8 System control and load dispatching.	-	-	
845.1 Fuel.	-	-	
845.2 Power.	-	-	
845.3 Rents.	-	-	
845.4 Demurrage charges.	-	-	
845.5 Wharfage receipts - credit.	-	-	
845.6 Processing liquefied or vaporized gas by others.	-	-	
846.1 Gas losses.	-	-	
846.2 Other expenses.	-	-	
Maintenance			
847.1 Maintenance supervision and engineering.	-	-	
847.2 Maintenance of structures and improvements.	-	-	
847.3 Maintenance of LNG processing terminal equipment.	-	-	
847.4 Maintenance of LNG transportation equipment.	-	-	
847.5 Maintenance of measuring and regulating equipment.	-	-	
847.6 Maintenance of compressor station equipment.	-	-	
847.7 Maintenance of communication equipment.	-	-	
847.8 Maintenance of other equipment.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
3. Transmission Expenses			
Operation			
850 Operation supervision and engineering.	-	-	
851 System control and load dispatching.	-	-	
852 Communication system expenses.	-	-	
853 Compressor station labor and expenses.	-	-	
854 Gas for compressor station fuel.	-	-	
855 Other fuel and power for compressor stations.	-	-	
856 Mains expenses.	-	-	
857 Measuring and regulating station expenses.	-	-	
858 Transmission and compression of gas by others.	-	-	
859 Other expenses.	-	-	
860 Rents.	-	-	
Maintenance			
861 Maintenance supervision and engineering.	-	-	
862 Maintenance of structures and improvements.	-	-	
863 Maintenance of mains.	-	-	
864 Maintenance of compressor station equipment.	-	-	
865 Maintenance of measuring and regulating station equipment.	-	-	
866 Maintenance of communication equipment.	-	-	
867 Maintenance of other equipment.	-	-	
870 Operation supervision and engineering.	3,587,963.41	958,493.13	26.7%
4. Distribution Expenses			
Operation			
871 Distribution load dispatching.	448,745.11	101,714.16	22.7%
872 Compressor station labor and expenses.	73,403.47	-	0.0%
873 Compressor station fuel and power (Major only).	-	-	
874 Mains and services expenses.	6,037,734.46	1,474,251.31	24.4%
875 Measuring and regulating station expenses - General.	720,920.52	200,480.57	27.8%
876 Measuring and regulating station expenses - Industrial.	228,308.71	43,646.97	19.1%
877 Measuring and regulating station expenses - City gate check stations.	-	-	
878 Meter and house regulator expenses.	1,591,100.64	292,202.43	18.4%
879 Customer installations expenses.	1,154,365.54	279,206.41	24.2%
880 Other expenses.	7,089,780.49	2,217,113.87	31.3%
881 Rents.	149,387.28	28,789.07	19.3%

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
Maintenance			
885 Maintenance supervision and engineering.	1,396,904.59	254,449.06	18.2%
886 Maintenance of structures and improvements.	21,819.52	441.35	2.0%
887 Maintenance of mains.	2,005,402.72	463,245.58	23.1%
888 Maintenance of compressor station equipment.	60,824.30	268.39	0.4%
889 Maintenance of measuring and regulating station equipment - General.	603,345.02	77,612.36	12.9%
890 Maintenance of measuring and regulating station equipment - Industrial.	51,855.19	5,854.94	11.3%
891 Maintenance of measuring and regulating station equipment - City gate check stations.	-	-	
892 Maintenance of services.	2,020,291.70	466,834.15	23.1%
893 Maintenance of meters and house regulators.	1,487,132.12	296,258.98	19.9%
894 Maintenance of other equipment.	1,444,918.65	431,934.44	29.9%
900-949 Customer Accounts, Customer Service and Informational, Sales and General and Administrative Expenses.			
5. Customer Accounts Expenses			
Operation			
901 Supervision.	174,902.80	44,451.26	25.4%
902 Meter reading expenses.	952,481.01	269,771.81	28.3%
903 Customer records and collection expenses.	6,431,639.85	1,655,826.56	25.7%
904 Uncollectible accounts.	866,122.01	171,038.07	19.7%
905 Miscellaneous customer accounts expenses.	7.04	1.77	25.1%
6. Customer Service and Informational Expenses			
Operation			
907 Supervision.	-	-	
908 Customer assistance expenses.	4,336,282.92	231,486.23	5.3%
909 Informational and instructional advertising expenses.	30,583.36	2,983.29	9.8%
910 Miscellaneous customer service and informational expenses.	395,030.40	99,350.18	25.2%
7. Sales Expenses			
Operation			
911 Supervision.	-	-	
912 Demonstrating and selling expenses.	-	-	
913 Advertising expenses.	2,839.46	1,292.81	45.5%
914 [Reserved]	-	-	
915 [Reserved]	-	-	
916 Miscellaneous sales expenses.	-	-	

Note that non Rate Base items are not allocable to State specific Trial Balances	Total Company Year 2018 Debit (Credit)	Oregon Year 2018 Debit (Credit)	OR Allocated %
8. Administrative and General Expenses			
Operation			
920 Administrative and general salaries.	8,549,939.41	2,150,309.67	25.1%
921 Office supplies and expenses.	4,162,213.26	1,057,858.64	25.4%
922 Administrative expenses transferred - Credit.	(357,024.65)	(101,230.48)	28.4%
923 Outside services employed.	1,591,557.16	577,828.19	36.3%
924 Property insurance.	81,985.67	20,619.39	25.1%
925 Injuries and damages.	1,330,293.31	360,488.80	27.1%
926 Employee pensions and benefits.	(372,205.71)	(94,704.03)	25.4%
927 Franchise requirements.	-	-	
928 Regulatory commission expenses.	-	-	
929 Duplicate charges - Credit.	-	-	
930.1 General advertising expenses.	405,452.75	102,462.42	25.3%
930.2 Miscellaneous general expenses.	796,594.95	203,227.72	25.5%
931 Rents.	1,569,365.80	403,147.34	25.7%
Maintenance			
932 Maintenance of general plant.	37,826.29	8,166.28	21.6%
	(0.00)		